UNDERGROUND INJECTION CONTROL
PERMIT APPLICATION AMENDMENT
FOR
PERMIT No. VAS3G931BSMY

BRINE INJECTION & RE-CIRCULATION OPERATION
AND
NATURAL GAS STORAGE FACILITY
LOCATED IN
SALTVILLE, VIRGINIA

Submitted to the Environmental Protection Agency:

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Prepared For:

Virginia Gas Pipeline Company

Operating Manager of the

Saltville Gas Storage Company, L.L.C.

Prepared by:

NUI Virginia Gas
New Ideas. Traditional Values.

and

LBL & ASSOCIATES, PC
ENVIRONMENTAL SERVICES DIVISION

November 12, 2003

Introduction

The Saltville Gas Storage Company, LLC, a partnership between Virginia Gas Pipeline Company-NUI and Duke Energy Gas Transmission, is developing a natural gas storage field in conjunction with a brine re-circulation and evaporation operation in Saltville, Virginia. The project is located in Washington and Smyth Counties.

The intention of the original UIC application was for authorization to create new future gas storage caverns via fresh water injection wells to leach enough void space to create suitable underground gas storage vessels as well as for authorization to dispose of the recovered fluids via drilling and utilizing Class I disposal wells. Since that time, the company has successfully converted six existing cavern wells (CH-16 and 20, CH-25 and 26, and CH-27 and 28) into suitable gas storage caverns and is currently in the process of converting the remaining five well gallery to gas storage as well. The company is no longer planning to utilize the previously permitted Class I disposal wells due to the construction of the evaporation facility. Of the three Class I wells permitted only one (EH-131) was drilled and then plugged once it was found to be unsuitable for brine disposal. However, the use of the Class III wells that have been permitted but not yet constructed could still be utilized for future development and expansion of the gas storage facility. Some minor modifications of the previously permitted Class III wells are discussed and included in the following application amendment.

Virginia Gas Pipeline Company is applying for an amendment to Underground Injection Control Permit No. VAS3G931BSMY from the Environmental Protection Agency. The primary purpose of this amendment will focus on injecting brine from the holding ponds and discharge water from the brine evaporation facility into an existing well cavern gallery on an as needed basis. The operation involves injecting brine from the brine holding ponds (Pond A, Pond B, and Pond C) and circulating the brine through the existing five well cavern gallery CH-18/19/21/22/23 to displace concentrated brine from the existing cavern with under-saturated brine from the holding ponds for enhanced brine processing at Virginia Gas' brine evaporation facility. The need for this operation is to maintain feed brine to the evaporation facility during the winter months when the gas storage facility is conducting gas withdrawal operations. Typically the brine is recovered via gas injections into the storage caverns during the summer months (April – October) when the facility is undergoing injection cycles. The brine evaporator plant is designed to operate with saturated feed brine, which is received from the brine holding ponds. Currently, there is not enough saturated brine within the holding ponds to maintain evaporation operations through the upcoming gas withdrawal season as may be the case during the future development of the gas storage facility. The minimum degree of feed brine saturation that the evaporator requires is estimated to be 80 to 82 percent, to prevent plant malfunction and even shut-down. The brine evaporation facility will be used to dispose of the excess brine recovered during gas storage operations. During times of low saturated brine storage, distilled water being discharged from the evaporation plant will be directed to the holding ponds for re-circulation into the existing cavern gallery to obtain the necessary brine saturation level to prevent a plant shut down.

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TABLES

FIGURES

APPENDICES

Form 4
Attachment A
Area of Review Methods

The area of review was determined to be a fixed radius of ¼ mile (1,320 feet) from the well bores circumscribing the project area. Mapping will extend to a one mile radius around the property facility boundary as specified in the UIC permit application instructions.

Form 4
Attachment B
Maps of Well/Area and Area of Review

See Figure 1 – Project Vicinity Map
See Figure 2 – Project Topographic Map
See Figure 3 – Facility Site Map

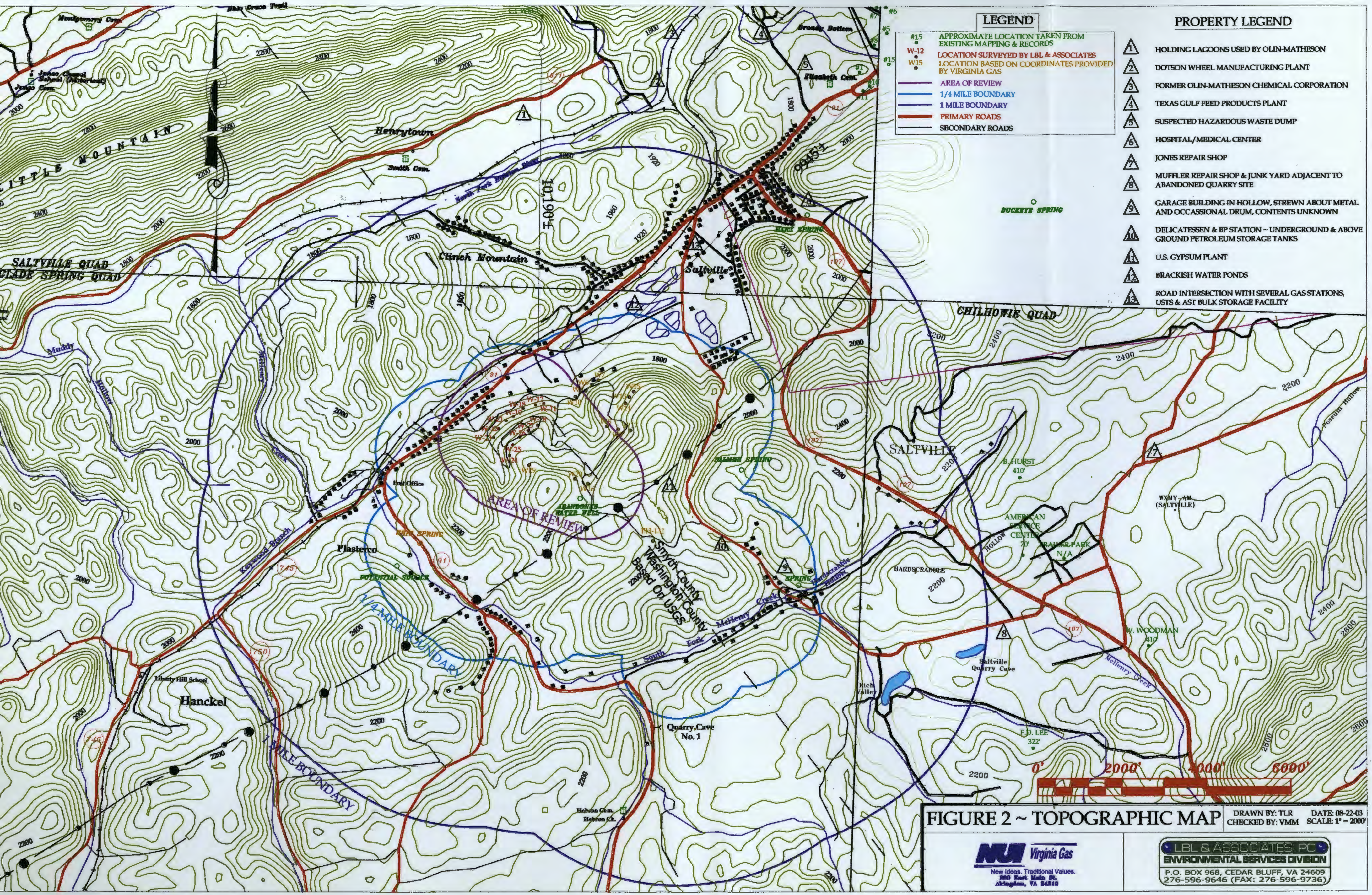
VICINITY MAP

NOT TO SCALE

FIGURE 1 ~ VICINITY MAP	DRAWN BY: TLR CHECKED BY: VMM	DATE: 08-22-03 NOT TO SCALE

NUI Virginia Gas
New Ideas. Traditional Values.
200 East Main St.
Abingdon, VA 24210

LBL & ASSOCIATES, PC
ENVIRONMENTAL SERVICES DIVISION
P.O. BOX 968, CEDAR BLUFF, VA 24609
276-596-9646 (FAX: 276-596-9736)


LEGEND
#15 APPROXIMATE LOCATION TAKEN FROM EXISTING MAPPING & RECORDS
W-12 LOCATION SURVEYED BY LBL & ASSOCIATES
W15 LOCATION BASED ON COORDINATES PROVIDED BY VIRGINIA GAS
AREA OF REVIEW
1/4 MILE BOUNDARY
1 MILE BOUNDARY
PRIMARY ROADS
SECONDARY ROADS
PROPERTY LEGEND
1 HOLDING LAGOONS USED BY OLIN-MATHESON
2 DOTSON WHEEL MANUFACTURING PLANT
3 FORMER OLIN-MATHESON CHEMICAL CORPORATION
4 TEXAS GULF FEED PRODUCTS PLANT
5 SUSPECTED HAZARDOUS WASTE DUMP
6 HOSPITAL/MEDICAL CENTER
7 JONES REPAIR SHOP
8 MUFFLER REPAIR SHOP & JUNK YARD ADJACENT TO ABANDONED QUARRY SITE
9 GARAGE BUILDING IN HOLLOW, STREWN ABOUT METAL AND OCCASSIONAL DRUM, CONTENTS UNKNOWN
10 DELICATESSEN & BP STATION ~ UNDERGROUND & ABOVE GROUND PETROLEUM STORAGE TANKS
11 U.S. GYPSUM PLANT
12 BRACKISH WATER PONDS
13 ROAD INTERSECTION WITH SEVERAL GAS STATIONS, USTS & AST BULK STORAGE FACILITY
SALTVILLE QUAD
CHILHOWIE QUAD
LITTLE MOUNTAIN
Henrytown
Clinch Mountain
Saltville
SALTVILLE
BUCKEYE SPRING
PALMER SPRING
AREA OF REVIEW
1/4 MILE BOUNDARY
1 MILE BOUNDARY
Smyth County
Washington County
Based On USGS
Plasterco
Post Office
Hanckel
Liberty Hill School
Quarry Cave No. 1
Saltville Quarry Cave
HARDSCRABBLE
Rich Valley
B. HURST 410'
W. WOODMAN 410'
F.D. LEE 322'
WXMY-AM (SALTVILLE)
TRAILER PARK N/A
Hebron Cem.
Hebron Ch.
South Fork
McHenry Creek
Muddy
Hollow
Broady Bottom
Elizabeth Cem.
Smith Cem.
0' 2000' 4000' 6000'
FIGURE 2 ~ TOPOGRAPHIC MAP
DRAWN BY: TLR
CHECKED BY: VMM
DATE: 08-22-03
SCALE: 1" = 2000'
NUI Virginia Gas
New Ideas. Traditional Values.
LBL & ASSOCIATES, PC
ENVIRONMENTAL SERVICES DIVISION
P.O. BOX 968, CEDAR BLUFF, VA 24609
276-596-9646 (FAX: 276-596-9736)

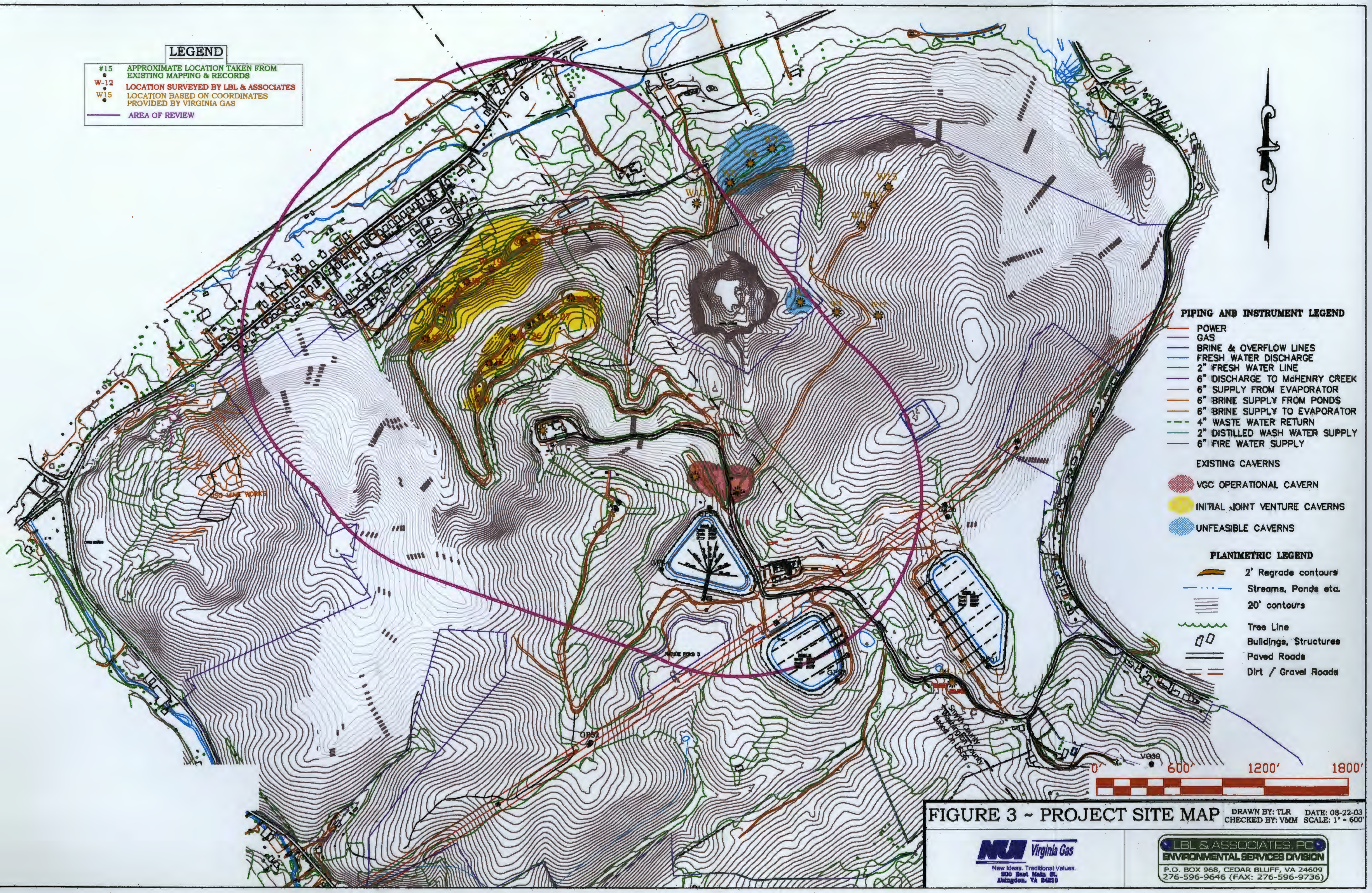


FIGURE 3 ~ PROJECT SITE MAP

Form 4
Attachment C
Corrective Action Plan and Well Data

The brine fluid and natural gas stored will be injected at less than the fracture pressure of the intended formations. The maximum surface injection pressure is based on information collected from the re-entering and reconditioning of the wells. Should the pressure be exceeded or other operating and injection problems be encountered, the following will be undertaken:

1. Immediately stop all fluid injection and allow the well to stabilize.

2. If the well cannot be stabilized and if the problems encountered cannot be corrected to the satisfaction of the state and federal agencies, the injection of fluids will cease and gas storage operations will continue.

3. Should an inactive well be discovered within the ¼ mile radius around the project area that was improperly plugged or unplugged, Virginia Gas Pipeline Company will plug said well in accordance with applicable state and federal regulations.

4. Should upward fluid migration occur through the well bore of any previously unknown well due to injection of permitted fluids, the injection of fluids will cease and gas storage operations will persist.

Fluid injection operations will not be resumed until the proper approval from the Director to recommence injection is received.

Available data for wells within the area of review and on the property of the Saltville Gas Storage Facility can be found in Table 1-Well Data for the Permit Injection Wells and Table 2-Well Data for Remaining Wells on the Property. This data includes well type, drill dates, plugging or completion dates, location and depths if available.

Table 1
Well Data for the Proposed Permit Injection Wells*

Well Name	Well Class Type	Construction	Date Drilled	Location Latitude	Location Longitude	Depth	Record or Plugging or Completion
CH-18	NA	Cased	NA	36°52'02"	81°46'40"	2965'	Converted for Gas Storage 2003
CH-22	NA	Cased	10/27/61	36°51'57"	81°46'47"	3190'	Under Gas Storage Conversion Construction
CH-23	NA	Cased	NA	36°51'55"	81°46'49"		Scheduled for Conversion 2003/ 2004

Table 2
Well Data for the Remaining Wells on the Property*

Well Name	Well Class Type	Construction	Date Drilled	Location Latitude	Location Longitude	Depth	Record or Plugging or Completion
CH-5	NA	P & A	09/01/35	36°52'06"	81°46'22"	1639'	12/09/72
CH-6	NA	P & A	09/01/35	36°52'08"	81°46'20"	1902'	12/09/72
CH-7	NA	P & A	02/18/38	36°52'09"	81°46'19"	1580'	12/09/72
CH-8	NA	Abandoned	03/22/43	36°51'58"	81°46'16"	N/A	N/A
CH-9	NA	P & A	06/01/46	36°51'57"	81°46'12"	2518'	12/07/72
CH-10	NA	P & A	10/05/51	36°52'05"	81°46'25"	1711'	11/27/72
CH-11	NA	Cased	01/14/52	36°52'03"	81°46'34"	2365'	11/28/72 - Re-enterd by VGPC in 2000-2001
CH-12	NA	Cased	05/03/52	36°52'03"	81°46'37"	2969'	11/23/72 - Re-enterd by VGPC in 2000-2001
CH-13	NA	P & A	03/27/53	36°52'05"	81°46'09"	2287'	12/06/72
CH-14	NA	P & A	08/18/54	36°52'04"	81°46'10"	2286'	11/29/72
CH-15	NA	P & A	09/23/55	36°52'06"	81°46'08"	2496'	12/05/72
CH-16	Gas Storage	Cased	1996	36°51'45"	81°46'21"	4015'	12/05/72 Converted to Storage Well in 1996
CH-17	NA	P & A	03/25/58	36°51'57"	81°46'09"	2468'	12/05/72
CH-19	NA	Cased	NA	36°52'00"	81°46'43"	2946'	Converted for Gas Storage 2003
CH-21	NA	Cased	02/03/61	36°51'59"	81°46'45"	2984'	Converted for Gas Storage 2003

CH-20	Gas Storage	Cased	11/24/62	36°51'46"	81°46'24"	3912'	12/04/72 Converted to Storage Well in 1996
CH-24	NA	Cased	11/17/63	36°51'51"	81°46'44"	3565'	12/03/72 Re-enterd by VGPC in 2001-2002
CH-25	Gas Storage	Cased	12/15/63	36°51'53"	81°46'43"	3406'	Converted to Storage 2002
CH-26	Gas Storage	Cased	NA	36°51'55"	81°46'41"	3372'	Converted to Storage 2002
CH-27	Gas Storage	Cased	NA	36°51'56"	81°46'39"	3315'	Converted to Storage 2003
CH-28	Gas Storage	Cased	NA	36°51'58"	81°46'36"	3286'	Converted to Storage 2003
CH-29	NA	P & A	NA	36°51'48"	81°46'38"	± 3000'	12/09/72
EH-131	IX	Plugged	10/11/96	36°51'32"	81°46'01"	9342'	10/11/2002

*

Data was taken from all available sources including lithologic descriptions, well plugging records, reentry information, mapping, etc. All information found is assumed to be accurate based on those records available. All wells listed above with exception to EH-131 were previously used as solution mining wells by Olin-Mathison Chemical Corp. circa 1940-1972. All were plugged in 1972 by OMCC with exception to EH-131 which was plugged by Virginia Gas on 10/11/2002.

Form 4
Attachment D
Maps and Cross Section of USDWs

The project area lies within the Valley and Ridge Regional Aquifer as defined by the Tennessee Valley Authority in their 1981 "Ground Water Quality Monitoring in the Tennessee Valley Region" by Wiley Harris. The groundwater of the aquifer occurs in solution openings, bedding planes, and joints in carbonates and sandstones. The Cambrian-Ordovician carbonates are considered to be high yielding and have good water quality. Recharge of the aquifer generally occurs along outcrop areas.

Wells located near the town of Saltville consist mainly of drilled wells into the Honaker, Nolichucky, and Copper Ridge dolomites with depths ranging from 70' to 1050'. Well locations can be found in Figure 2 and data on wells in the area is located in Table 3. Note that these wells are not within the area of review, ¼ mile or mile radius around the property boundary. Within the area of review only one shallow hand-dug well was located and no records are known to exist. One spring locally known as Whitt Spring near Plasterco was identified within the one mile of the property boundary. This spring is occasionally used by the Town of Saltville as a back-up water supply. The Town of Saltville gets its water from two different sources (Cardwell Town Well located in the Poor Valley area and the No. 10 Well located in the Broady Bottom Area). The Cardwell Town Well is approximately 450' deep, draws groundwater from the Tonoloway Limestone aquifer, and is approximately 1.93 miles from the area of review. The No. 10 Well is approximately 1,050' deep, draws groundwater from the Honaker Formation aquifer, and is approximately 1.88 miles away from the area of review.

Table 3
Local Fresh Water Well Data

Well No.	Total Depth (ft.)	Depth Cased (ft.)	Casing Size (in.)	Static water level (ft.)	Capacity (gpm)	Comments
1[1]	816	200	13 3/8	NA	450	
5[1]	928	93	16	11	400	Texas Gulf Corp - cooling
6[1]	678	147	16	60	100	
7[1]	450	200	13 3/8	17	300	
8[1]	NA	NA	NA	NA	NA	Texas Gulf Corp - cooling
10[1]	1050	33	20	100	240	Saltville – Drinking
11[1]	582	258	16	96	700	
14[1]	500	66	20	NA	750	
15[1]	866	65	20	8	275	
CT[1,2]	419	NA	12	Overflows	750	Saltville - Drinking
Whit	Surface spring	NA	NA	NA	190	Back-up Drinking Supply for Saltville
B. Hurst	410	NA	NA	NA	NA	Private
American Service Center	70	NA	NA	NA	NA	Private
Trailer Park	NA	NA	NA	NA	NA	Private
W. Woodward	410	NA	NA	NA	NA	Private
F.D. Lee	322	NA	NA	NA	NA	Private

[1] Wells given to the Town of Saltville by Olin Corporation [2] Cardwell Town Well

Form 4
Attachment F
Maps and Cross Sections of Geologic Structure of Area

The project lies within the Valley and Ridge Physiographic Province of Virginia. The geology of the area consists of sedimentary rocks including limestone, dolomite, and shale. To the west of the Blue Ridge, consolidated sedimentary rocks are deposited beneath ancient seas. The area is unique in that this is the only known deposit of native rock salt to exist in the Southern Appalachian Basin. The salt deposits occur in the Mississippian aged MacCrady Formation and lesser amounts are found in the adjacent overlying Mississippian aged Little Valley Formation. See Figure 4. The salt-bearing formations and other enclosing sedimentary strata have been drastically bent into a northeast trending structure known as the overturned Greendale Syncline. The paralleling Saltville Thrust Fault was also created with this folding. That caused older Ordovician and Cambrian dolomites, shales, and limestones to be pushed northwestward over younger salt bearing formations.

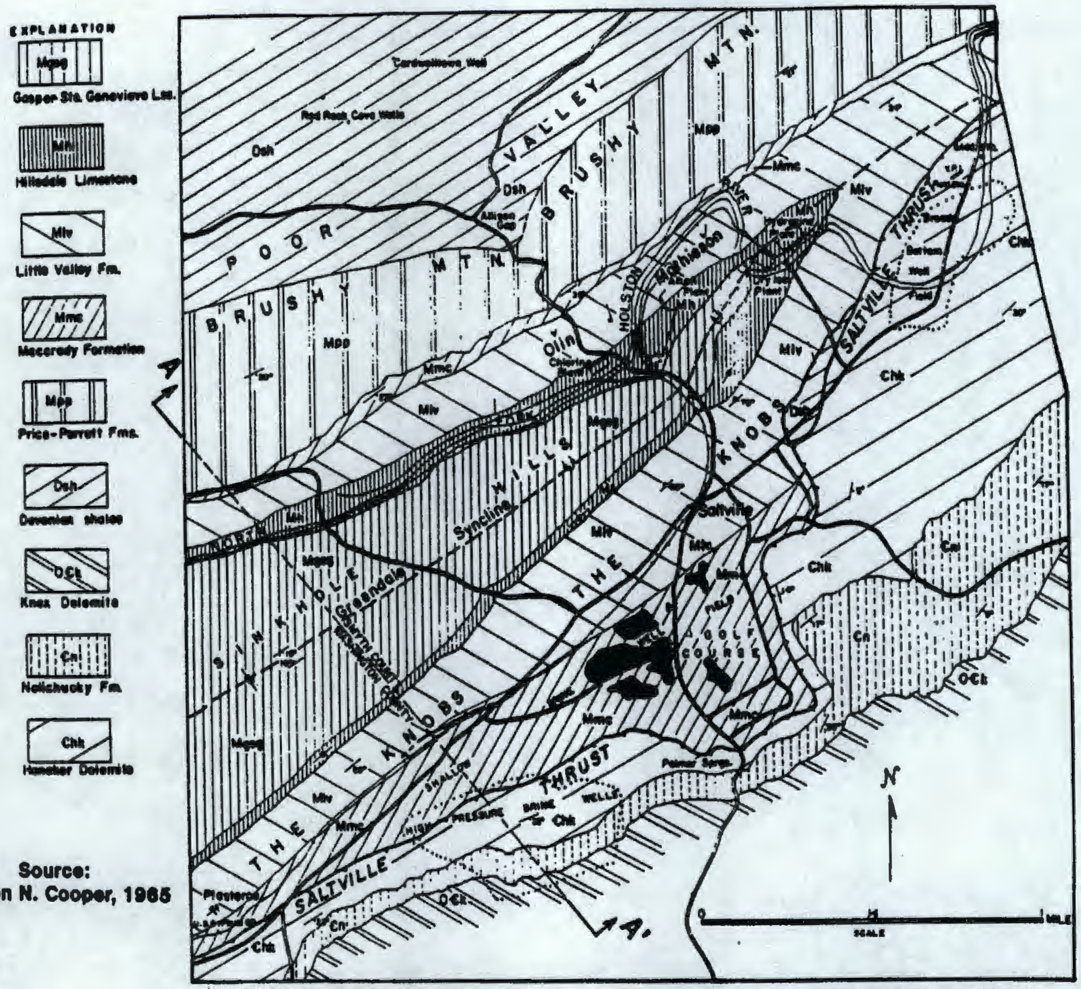
The geological data on the injection zone and the confining zones including geological name, thickness, and depth are in Table 4. See Appendix A for lithologic descriptions available from the original well borings for wells CH-18, CH-21, CH-22, and CH-25.

Fracture pressures for the formations are irrelevant in the case of these preexisting wells. The intention of these wells is to maintain tight caverns and due to the well casing system that is in place, the injection will not pose any pressure on the formations above the cavern. The MIT test which has been run on cavern galleries 25/26 and 27/28 were tested using a 0.80 gradient to the shallowest casing shoe of each cavern gallery and the MIT for gallery 18/19/21/22/23 will be conducted in the same manner. The caverns will essentially be hydrostatically tested to about 2400 psi. The proposed plan is to recirculate at approximately 800-1000 psi which gives a pressure gradient that will not exceed the regulatory prescribed pressure gradient. The Virginia State Corporation Commission (SCC) granted the facility a 0.75 gradient for the Maximum Allowable Operating Pressure (MAOP) of the cavern for gas storage.

Table 4
Geological Data

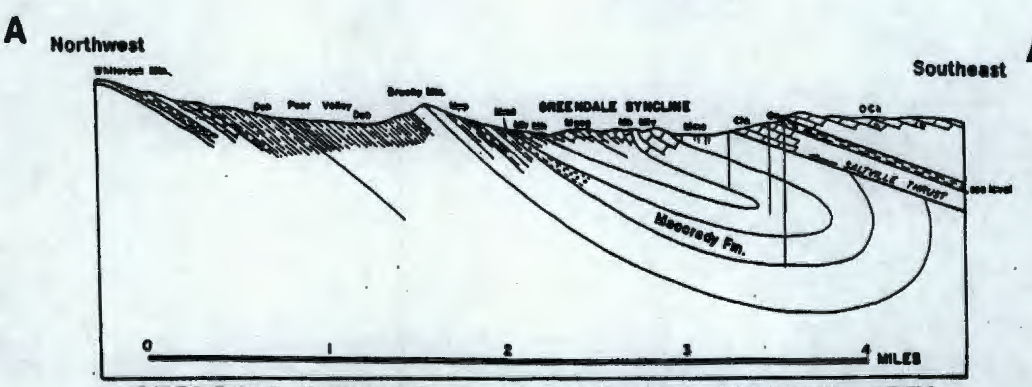
Depth	Thickness	Geological Formation Name
Surface – 495’	495’	Copper Ridge Formation
495’ – 1,025’	530’	Nolichucky Formation
1,025’ – 1,404’	379’	Honaker Dolomite
1,404’ – 3,954’	2550’	MacCrady Formation

Figure 4
Geologic Plan and Cross Section Map of Saltville, VA



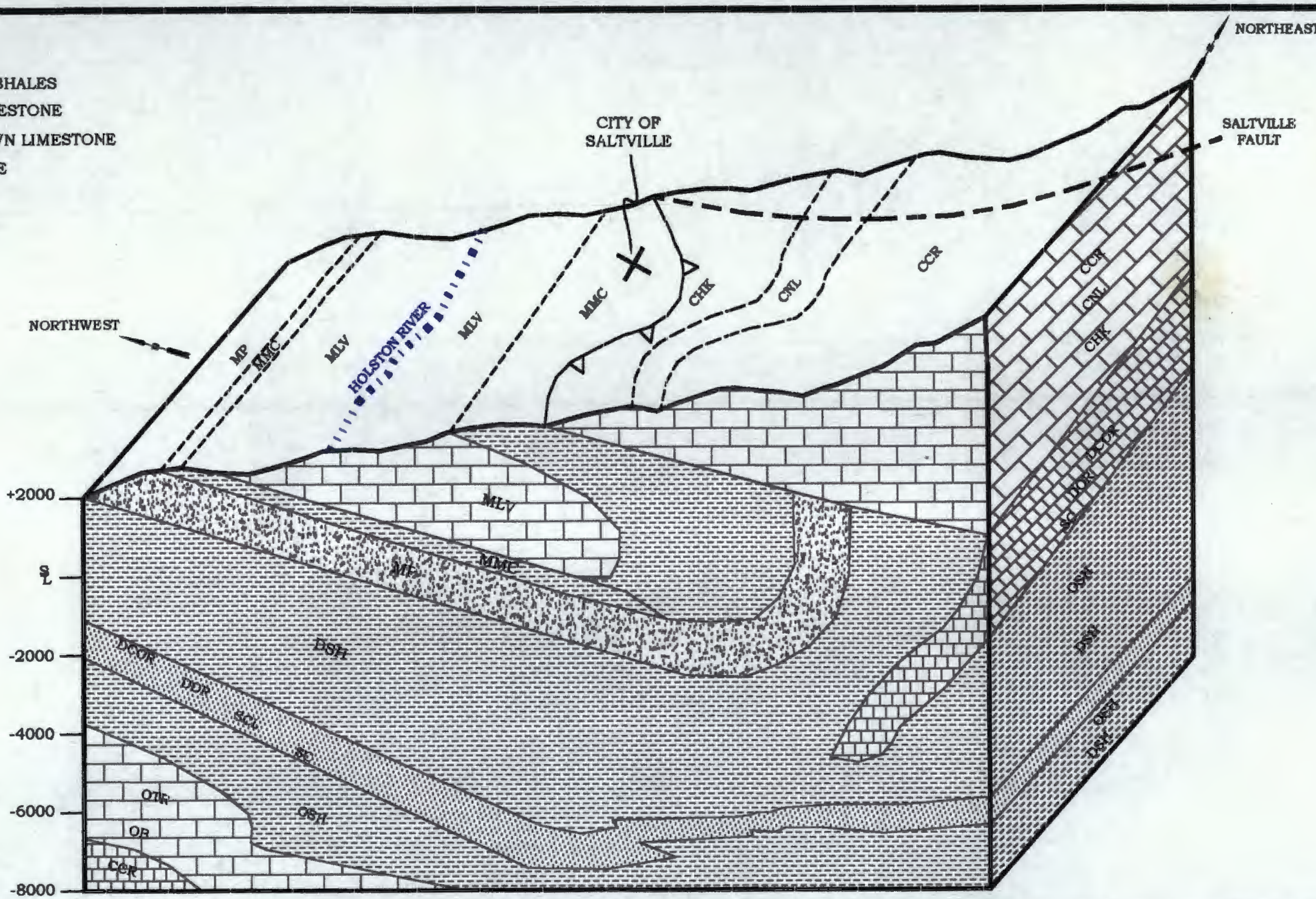
Source:
Byron N. Cooper, 1965

GEOLOGIC PLAN MAP OF SALTVILLE, VIRGINIA AREA



GEOLOGIC SECTION A–A', SALTVILLE, VIRGINIA AREA

SC	CLINCH
OSH	ORDOVICIAN SHALES
OTR	TRENTON LIMESTONE
OB	BEEKMANTOWN LIMESTONE
CCR	COPPER RIDGE
CNL	NOLICHUCKY
CHK	HONAKER



MLV	LITTLE VALLEY
MMC	MACCRADY
MP	PRICE
DSH	DEVONIAN SHALES
DCOR	CORNIFEROUS
DOR	ORISKANY EQUIVALENT
SCL	CLINTON

FIGURE 5

GEOLOGICAL FORMATIONS CROSS~SECTION

DRAWN BY: TLR
CHECKED BY: VMM

DATE: 08-22-03
NOT TO SCALE

NUI Virginia Gas
New Ideas. Traditional Values.
200 East Main St.
Abingdon, VA 24210

LBL & ASSOCIATES, PC
ENVIRONMENTAL SERVICES DIVISION
P.O. BOX 968, CEDAR BLUFF, VA 24609
276-596-9646 (FAX: 276-596-9736)

Form 4
Attachment H
OPERATING DATA

Operating Data Class I-1X Wells

The company is no longer pursuing the use of Class I-1X injection wells. Only one (EH-131) of the formerly three permitted Class I-1x wells have been drilled to date and after extensive testing it has been concluded that the formations in the area are not suitable for brine disposal. The EH-131 well was plugged in October of 2002. A 100-gpm salt evaporation plant was built in 1999 and now serves as the means of brine disposal in lieu of disposal via underground injection. Construction of a new 400-gpm evaporation facility began in the summer of 2002 for future support of the natural gas cavern expansion project which will increase underground gas storage capacity from 1 billion cubic feet of storage to approximately 7 billion cubic feet.

Operating Data Class III Wells (Proposed & Previously Permitted)

The only change being requested for this data is for an additional and primary source of fresh water. The evaporator plant distilled discharge is being requested as the new primary source of fresh water for future cavern leaching operations. The distilled discharge is currently being routed to a nearby point along McHenry Creek and is regulated by Virginia's Department of Environmental Quality via VPDES Permit No. VA0090115. EPA approval for the use this distillate as a source of water for leaching would eliminate the majority of this discharge to the creek and reduce the risk of environmental damages to the local surface waters. An analysis of the discharged distillate is included in the analytical section at the end of this attachment.

Operating Data Class III Wells (Existing Wells CH-18, CH-22 and CH-23)

The wells will serve dual purposes as natural gas storage units and for brine injection or recirculation operations. Primarily the brine will be injected to maintain feed brine to the evaporator plant during the winter months (November through March) when the gas is in greatest demand and being withdrawn from the storage caverns. Other reasons for the brine injection or recirculation include cavern testing for communication, mechanical integrity testing, and brine re-saturation for enhanced salt recovery at the brine evaporator plant.

The amount of pressure required for injection will be controlled and limited to 800-1000 psig shut-in pressure at the wellheads. This was the discovered pressure during cavern re-entry and will not be exceeded. The cushion pressure (minimum amount of cavern pressure necessary to support the earth load above the cavern) varies for all of the wells depending on their depth.

The proposed volume for the operations will consist of an estimated 600,000 – 800,000 bbls of 10% saturated brine fluid to be injected into the existing wells/galleries during a calendar year.

The maximum daily volume of brine injected is estimated to be 5,000 barrels (210,000 gallons) per gallery per day. The maximum daily rate of fluid injected is based on injecting at a rate of 145 gpm.

Analytical Data

The source and analysis of the physical and chemical characteristics of the injection fluid from the brine ponds, existing caverns, and evaporation plant discharge are on the following pages.

Tri-State Analytical Laboratory, L.L.C.

P.O. Box 2024 Johnson City, TN 37605
Telephone: 423-926-6385 Fax: 423-926-6997
EPA Laboratory Number TN00020

CERTIFICATE OF REPORT

Report Date: 6/14/2001

Report To: Joey Sauls
Virginia Salt Co.
P.O. Box K
Saltville, VA 24370

Account Code: VASALT01
Location Code: VASALT

LOG-IN RECORD # 60821

Sample Location/Description Virginia Salt Co.
Pond C Brine

Sample ID # AB50508 **Sample Collection Date:** **Time:** **Received in Lab:** 6/12/2001

Parameter	Result	MDL OQL	Unit of Measure	Method	Analysis Start Date/Time		Analyst
Carbonate	**0.1**	0.1	mg/l CaCO3	SM 4500D	6/14/2001	12:00	KM
Chloride	**160000**	1	mg/l	EPA 325.3	6/13/2001	14:00	KM
Sulfate	**3375**	1	mg/l	EPA 375.4	6/12/2001	9:00	CS
Total Dissolved Solids	**181000**	1	mg/l	EPA 160.1	6/13/2001	13:20	CW
Total Suspended Solids	**68.7**	2.0	mg/l	EPA 160.2	6/12/2001	10:00	CW
Sulfur	**<0.01**		%	ASTM-D4239	6/12/2001	9:00	CS
Barium	**4.0**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Calcium	**1820**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Copper	**<0.1**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Iron	**0.3**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Lead	**<0.1**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Magnesium	**75.1**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Mercury	**<0.0002**	0.0002	mg/l	EPA 245.2	6/14/2001	8:30	HS
Nickel	**2.6**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Potassium	**253**	0.1	mg/l	EPA 258.1	6/13/2001	15:45	JF
Silica	**24.2**	0.1	mg/l	EPA 200.7	6/14/2001	11:15	JF
Sodium	**112000**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
PCB 1016	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:13	JJ
PCB 1221	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:13	JJ
PCB 1232	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:13	JJ
PCB 1242	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:13	JJ
PCB 1248	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:13	JJ
PCB 1254	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:13	JJ
PCB 1260	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:13	JJ

FOOTNOTES (If applicable):

MDL = Minimum Detection Limit | **OQL = Organics Quantitation Limit**
< "Less Than" > "Greater Than" | J = Estimated Value
If Sample Result = **, Unable to determine due to nature of sample | MDL / OQL column for surrogates represents % recovery
If Sample Result = ***, See COMMENTS | MDL / OQL column for library search compounds (*) represents % match quality

COMMENTS:

FORMAT: MultiFNP

Sheryl C. Gibson
Sheryl C. Gibson, Data Analyst

Tri-State Analytical Laboratory, L.L.C.

P.O. Box 2024 Johnson City, TN 37605
Telephone: 423-926-6385 Fax: 423-926-6997

EPA Laboratory Number TN00020

CERTIFICATE OF REPORT

Report Date: 12/2/2002

Report To: Barry Buchanan
NUI - Virginia Gas Company
1096 Ole Berry Dr.
Abingdon, VA 24210

Account Code: VAGAS01
Location Code: VAGAS

Parameter	Result	MDL OQL	Unit of Measure	Method	Analysis Start Date/Time		Analyst
Sample Location/Description Virginia Gas Brine Holding Pond A					**LOG-IN RECORD #** 66546 **Matrix:** Wastewater		
Sample ID # AB64581	**Sample Collection Date:** 11/4/2002		**Time:** 1:48 PM		**Received in Lab:** 11/4/2002		
pH - Field	7.7	0.1	s.u.	EPA 150.1	11/4/2002	13:48	RH
Temperature (Field) Degrees F	52		Degrees F	EPA 170.1	11/4/2002	13:48	RH
Chloride	107200	1	mg/l	EPA 325.3	11/21/2002	11:00	CW
Conductivity	70951	1	micromhos/cm	EPA 120.1	11/19/2002	15:45	CW
Total Dissolved Solids	54910	1	mg/l	EPA 160.1	11/11/2002	12:00	JM
Sodium	28800	0.1	mg/l	EPA 200.7	11/8/2002	12:25	JF
Sample Location/Description Virginia Gas Brine Holding Pond C					**LOG-IN RECORD #** 66546 **Matrix:** Wastewater		
Sample ID # AB64582	**Sample Collection Date:** 11/4/2002		**Time:** 1:05 PM		**Received in Lab:** 11/4/2002		
pH - Field	6.8	0.1	s.u.	EPA 150.1	11/4/2002	13:05	RH
Temperature (Field) Degrees F	58		Degrees F	EPA 170.1	11/4/2002	13:05	RH
Chloride	23000	1	mg/l	EPA 325.3	11/21/2002	11:00	CW
Conductivity	104879	1	micromhos/cm	EPA 120.1	11/19/2002	15:45	CW
Sample Location/Description Virginia Gas Brine Holding Pond B					**LOG-IN RECORD #** 66546 **Matrix:** Wastewater		
Sample ID # AB64583	**Sample Collection Date:** 11/4/2002		**Time:** 12:15 PM		**Received in Lab:** 11/4/2002		
pH - Field	8.9	0.1	s.u.	EPA 150.1	11/4/2002	12:15	RH
Temperature (Field) Degrees F	54		Degrees F	EPA 170.1	11/4/2002	12:15	RH
Chloride	995	1	mg/l	EPA 325.3	11/21/2002	11:00	CW
Conductivity	2914	1	micromhos/cm	EPA 120.1	11/19/2002	15:45	CW
Sample Location/Description Virginia Gas Brine HoldingPond Leak Detection Manhole A-1					**LOG-IN RECORD #** 66546 **Matrix:** Wastewater		
Sample ID # AB64584	**Sample Collection Date:** 11/4/2002		**Time:** 1:56 PM		**Received in Lab:** 11/4/2002		
pH - Field	8.2	0.1	s.u.	EPA 150.1	11/4/2002	13:56	RH
Temperature (Field) Degrees F	55		Degrees F	EPA 170.1	11/4/2002	13:56	RH
Chloride	32	1	mg/l	EPA 325.3	11/21/2002	11:00	CW
Conductivity	300	1	micromhos/cm	EPA 120.1	11/19/2002	15:45	CW

FOOTNOTES (If applicable):

MDL = Minimum Detection Limit — **OQL = Organics Quantitation Limit**
< "Less Than" > "Greater Than" — J = Estimated Value
If Sample Result = **, Unable to determine due to nature of sample — MDL / OQL column for surrogates represents % recovery
If Sample Result = ***, See COMMENTS — MDL / OQL column for library search compounds (*) represents % match quality.

COMMENTS:

FORMAT: MULTI

Tri-State Analytical Laboratory, L.L.C.

P.O. Box 2024 Johnson City, TN 37605
Telephone: 423-926-6385 Fax: 423-926-6997
EPA Laboratory Number TN00020

CERTIFICATE OF REPORT

Report Date: 6/14/2001

Report To: Joey Sauls
Virginia Salt Co.
P.O. Box K
Saltville, VA 24370

Account Code: VASALT01
Location Code: VASALT

LOG-IN RECORD # 60821

Sample Location/Description Virginia Salt Co.
CH-18

Sample ID # AB50523 **Sample Collection Date:** **Time:** **Received in Lab:** 6/12/2001

Parameter	Result	MDL OQL	Unit of Measure	Method	Analysis Start Date/Time		Analyst
Carbonate	**4.0**	0.1	mg/l CaCO3	SM 4500D	6/14/2001	12:00	KM
Chloride	**229000**	1	mg/l	EPA 325.3	6/13/2001	14:00	KM
Sulfate	**3475**	1	mg/l	EPA 375.4	6/12/2001	9:00	CS
Total Dissolved Solids	**208000**	1	mg/l	EPA 160.1	6/13/2001	13:20	CW
Total Suspended Solids	**134**	2.0	mg/l	EPA 160.2	6/12/2001	10:00	CW
Sulfur	**<0.01**		%	ASTM-D4239	6/12/2001	9:00	CS
Barium	**5.1**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Calcium	**2180**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Copper	**<0.1**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Iron	**2.7**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Lead	**<0.1**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Magnesium	**43.4**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Mercury	**<0.0002**	0.0002	mg/l	EPA 245.2	6/14/2001	8:30	HS
Nickel	**3.2**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Potassium	**403**	0.1	mg/l	EPA 258.1	6/13/2001	15:45	JF
Silica	**17.6**	0.1	mg/l	EPA 200.7	6/14/2001	11:15	JF
Sodium	**125000**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
PCB 1016	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:51	JJ
PCB 1221	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:51	JJ
PCB 1232	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:51	JJ
PCB 1242	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:51	JJ
PCB 1248	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:51	JJ
PCB 1254	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:51	JJ
PCB 1260	**Not detected**	1	ug/l	EPA 608	6/12/2001	20:51	JJ

FOOTNOTES (If applicable):

MDL = Minimum Detection Limit
< "Less Than" > "Greater Than"
If Sample Result = **, Unable to determine due to nature of sample
If Sample Result = ***, See COMMENTS

OQL = Organics Quantitation Limit
J = Estimated Value
MDL / OQL column for surrogates represents % recovery
MDL / OQL column for library search compounds (*) represents % match quality

COMMENTS:

Sheryl C Gibson
Sheryl C. Gibson, Data Analyst

FORMAT: MultiFNP

Tri-State Analytical Laboratory, L.L.C.

P.O. Box 2024 Johnson City, TN 37605
Telephone: 423-926-6385 Fax: 423-926-6997
EPA Laboratory Number TN00020

CERTIFICATE OF REPORT

Report Date: 6/14/2001

Report To: Joey Sauls
Virginia Salt Co.
P.O. Box K
Saltville, VA 24370

Account Code: VASALT01
Location Code: VASALT

LOG-IN RECORD # 60821

Sample Location/Description Virginia Salt Co.
CH-22

Sample ID # AB50524 **Sample Collection Date:** **Time:** **Received in Lab:** 6/12/2001

Parameter	Result	MDL OQL	Unit of Measure	Method	Analysis Start Date/Time		Analyst
Carbonate	**68.4**	0.1	mg/l CaCO3	SM 4500D	6/14/2001	12:00	KM
Chloride	**206000**	1	mg/l	EPA 325.3	6/13/2001	14:00	KM
Sulfate	**3875**	1	mg/l	EPA 375.4	6/12/2001	9:00	CS
Total Dissolved Solids	**217000**	1	mg/l	EPA 160.1	6/13/2001	13:20	CW
Total Suspended Solids	**83.7**	2.0	mg/l	EPA 160.2	6/12/2001	10:00	CW
Sulfur	**<0.01**		%	ASTM-D4239	6/12/2001	9:00	CS
Barium	**5.3**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Calcium	**2140**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Copper	**<0.1**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Iron	**<0.1**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Lead	**<0.1**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Magnesium	**3.4**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Mercury	**<0.0002**	0.0002	mg/l	EPA 245.2	6/14/2001	8:30	HS
Nickel	**3.3**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Potassium	**331**	0.1	mg/l	EPA 258.1	6/13/2001	15:45	JF
Silica	**14.7**	0.1	mg/l	EPA 200.7	6/14/2001	11:15	JF
Sodium	**126000**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
PCB 1016	**Not detected**	1	ug/l	EPA 608	6/12/2001	21:30	JJ
PCB 1221	**Not detected**	1	ug/l	EPA 608	6/12/2001	21:30	JJ
PCB 1232	**Not detected**	1	ug/l	EPA 608	6/12/2001	21:30	JJ
PCB 1242	**Not detected**	1	ug/l	EPA 608	6/12/2001	21:30	JJ
PCB 1248	**Not detected**	1	ug/l	EPA 608	6/12/2001	21:30	JJ
PCB 1254	**Not detected**	1	ug/l	EPA 608	6/12/2001	21:30	JJ
PCB 1260	**Not detected**	1	ug/l	EPA 608	6/12/2001	21:30	JJ

FOOTNOTES (If applicable):

MDL = Minimum Detection Limit
< "Less Than" > "Greater Than"
If Sample Result = **, Unable to determine due to nature of sample
If Sample Result = ***, See COMMENTS

OQL = Organics Quantitation Limit
J = Estimated Value
MDL / OQL column for surrogates represents % recovery
MDL / OQL column for library search compounds (*) represents % match quality

COMMENTS:

Sheryl C. Gibson

Sheryl C. Gibson, Data Analyst

FORMAT: MultiFNP

Tri-State Analytical Laboratory, L.L.C.

P.O. Box 2024 Johnson City, TN 37605
Telephone: 423-926-6385 Fax: 423-926-6997
EPA Laboratory Number TN00020

CERTIFICATE OF REPORT

Report Date: 6/14/2001

Report To: Joey Sauls
Virginia Salt Co.
P.O. Box K
Saltville, VA 24370

Account Code: VASALT01
Location Code: VASALT

LOG-IN RECORD # 60821

Sample Location/Description Virginia Salt Co.
CH-23

Sample ID # AB50525 **Sample Collection Date:** **Time:** **Received in Lab:** 6/12/2001

Parameter	Result	MDL OQL	Unit of Measure	Method	Analysis Start Date/Time		Analyst
Carbonate	<0.1	0.1	mg/l CaCO3	SM 4500D	6/14/2001	12:00	KM
Chloride	200000	1	mg/l	EPA 325.3	6/13/2001	14:00	KM
Sulfate	3575	1	mg/l	EPA 375.4	6/12/2001	9:00	CS
Total Dissolved Solids	231000	1	mg/l	EPA 160.1	6/13/2001	13:20	CW
Total Suspended Solids	298	2.0	mg/l	EPA 160.2	6/12/2001	10:00	CW
Sulfur	<0.01		%	ASTM-D4239	6/12/2001	9:00	CS
Barium	4.6	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Calcium	1930	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Copper	<0.1	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Iron	6.6	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Lead	<0.1	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Magnesium	104	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Mercury	<0.0002	0.0002	mg/l	EPA 245.2	6/14/2001	8:30	HS
Nickel	3.0	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Potassium	371	0.1	mg/l	EPA 258.1	6/13/2001	15:45	JF
Silica	32.1	0.1	mg/l	EPA 200.7	6/14/2001	11:15	JF
Sodium	126000	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
PCB 1016	Not detected	1	ug/l	EPA 608	6/12/2001	22:08	JJ
PCB 1221	Not detected	1	ug/l	EPA 608	6/12/2001	22:08	JJ
PCB 1232	Not detected	1	ug/l	EPA 608	6/12/2001	22:08	JJ
PCB 1242	Not detected	1	ug/l	EPA 608	6/12/2001	22:08	JJ
PCB 1248	Not detected	1	ug/l	EPA 608	6/12/2001	22:08	JJ
PCB 1254	Not detected	1	ug/l	EPA 608	6/12/2001	22:08	JJ
PCB 1260	Not detected	1	ug/l	EPA 608	6/12/2001	22:08	JJ

FOOTNOTES (If applicable):

MDL = Minimum Detection Limit
< "Less Than" > "Greater Than"
If Sample Result = **, Unable to determine due to nature of sample
If Sample Result = ***, See COMMENTS

OQL = Organics Quantitation Limit
J = Estimated Value
MDL / OQL column for surrogates represents % recovery
MDL / OQL column for library search compounds (*) represents % match quality

COMMENTS:

Sheryl C. Gibson

Sheryl C. Gibson, Data Analyst

FORMAT: MultiFNP

Tri-State Analytical Laboratory, L.L.C.
P.O. Box 2024 Johnson City, TN 37605
Telephone: 423-926-6385 Fax: 423-926-6997
EPA Laboratory Number TN00020

CERTIFICATE OF REPORT

Report Date: 11/1/2002

Report To: Joey Sauls
Virginia Gas Co.
486 Ader Lane
Saltville, VA 24370

Account Code: VASALT01
Location Code: VASALT

LOG-IN RECORD # 66457

Sample Location/Description Virginia Gas / Virginia Salt
CH 25/26

Matrix: Aqueous

Sample ID # AB64392 **Sample Collection Date:** 10/24/2002 **Time:** **Received in Lab:** 10/28/2002

Parameter	Result	MDL OQL	Unit of Measure	Method	Analysis Start Date/Time		Analyst
INORGANI							
Chloride	200000	1	mg/l	SW846-9252	10/28/2002	10:30	JM
Conductivity	133947	1	micromhos/cm	EPA 120.1	10/29/2002	11:00	JM
pH	6.0	0.1	s.u.	EPA 150.1	10/30/2002	15:00	CS
Total Dissolved Solids	252000	1	mg/l	EPA 160.1	10/31/2002	13:00	JM
METALS							
Arsenic	<0.1	0.1	mg/l	SW846-6010B	10/30/2002	13:45	JF
Barium	<0.1	0.1	mg/l	SW846-6010B	10/30/2002	13:45	JF
Cadmium	<0.1	0.1	mg/l	SW846-6010B	10/30/2002	13:45	JF
Chromium	<0.1	0.1	mg/l	SW846-6010B	10/30/2002	13:45	JF
Lead	<0.1	0.1	mg/l	SW846-6010B	10/30/2002	13:45	JF
Mercury	<0.0002	0.0002	mg/l	SW846-7470	10/31/2002	14:00	JC
Selenium	<0.1	0.1	mg/l	SW846-6010B	10/30/2002	13:45	JF
Silver	<0.1	0.1	mg/l	SW846-6010B	10/30/2002	13:45	JF
Sodium	124000	0.1	mg/l	SW846-6010B	10/31/2002	12:10	JF

FOOTNOTES (if applicable):
MDL = Minimum Detection Limit
< "Less Than" > "Greater Than"
c f u = Colony Forming Unit
If Sample Result = "", Unable to determine due to nature of sample
OQL = Organica Quantitation Limit
J = Estimated Value
MDL / OQL column for surrogates represents % recovery
MDL / OQL column for library search compounds (*) represents % match quality.

COMMENTS:

FORMAT: SINGLE

Sheryl C. Freeman
Sheryl C. Freeman, Data Analyst

Tri-State Analytical Laboratory, L.L.C.

P.O. Box 2024 Johnson City, TN 37605
Telephone: 423-926-6385 Fax: 423-926-6997
EPA Laboratory Number TN00020

CERTIFICATE OF REPORT

Report Date: 6/14/2001

Report To: Joey Sauls
Virginia Salt Co.
P.O. Box K
Saltville, VA 24370

Account Code: VASALT01
Location Code: VASALT

LOG-IN RECORD # 60821

Sample Location/Description Virginia Salt Co.
CH-27

Sample ID # AB50526 **Sample Collection Date:** **Time:** **Received in Lab:** 6/12/2001

Parameter	Result	MDL OQL	Unit of Measure	Method	Analysis Start Date/Time		Analyst
Carbonate	**1.1**	0.1	mg/l CaCO3	SM 4500D	6/14/2001	12:00	KM
Chloride	**190000**	1	mg/l	EPA 325.3	6/13/2001	14:00	KM
Sulfate	**2350**	1	mg/l	EPA 375.4	6/12/2001	9:00	CS
Total Dissolved Solids	**225000**	1	mg/l	EPA 160.1	6/13/2001	13:20	CW
Total Suspended Solids	**104**	2.0	mg/l	EPA 160.2	6/12/2001	10:00	CW
Sulfur	**<0.01**		%	ASTM-D4239	6/12/2001	9:00	CS
Barium	**4.8**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Calcium	**2970**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Copper	**<0.1**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Iron	**0.7**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Lead	**0.1**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Magnesium	**163**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Mercury	**<0.0002**	0.0002	mg/l	EPA 245.2	6/14/2001	8:30	HS
Nickel	**3.0**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
Potassium	**752**	0.1	mg/l	EPA 258.1	6/13/2001	15:45	JF
Silica	**16.8**	0.1	mg/l	EPA 200.7	6/14/2001	11:15	JF
Sodium	**123000**	0.1	mg/l	EPA 200.7	6/13/2001	15:00	JF
PCB 1016	**Not detected**	1	ug/l	EPA 608	6/12/2001	22:47	JJ
PCB 1221	**Not detected**	1	ug/l	EPA 608	6/12/2001	22:47	JJ
PCB 1232	**Not detected**	1	ug/l	EPA 608	6/12/2001	22:47	JJ
PCB 1242	**Not detected**	1	ug/l	EPA 608	6/12/2001	22:47	JJ
PCB 1248	**Not detected**	1	ug/l	EPA 608	6/12/2001	22:47	JJ
PCB 1254	**Not detected**	1	ug/l	EPA 608	6/12/2001	22:47	JJ
PCB 1260	**Not detected**	1	ug/l	EPA 608	6/12/2001	22:47	JJ

FOOTNOTES (If applicable):

MDL = Minimum Detection Limit
< "Less Than" > "Greater Than"
If Sample Result = **, Unable to determine due to nature of sample
If Sample Result = ***, See COMMENTS

OQL = Organics Quantitation Limit
J = Estimated Value
MDL / OQL column for surrogates represents % recovery
MDL / OQL column for library search compounds (*) represents % match quality

COMMENTS:

Sheryl C. Gibson

Sheryl C. Gibson, Data Analyst

FORMAT: MultiFNP

ENVIRONMENTAL MONITORING, INCORPORATED
ENVIRONMENTAL CONSULTANTS ▲ ANALYTICAL LABORATORIES
P.O. BOX 1477 ▲ COEBURN, VIRGINIA 24230 ▲ 276/395-3661

Certificate of Analysis

Client Name: VIRGINIA GAS COMPANY
Address: 200 EAST MAIN STREET
ABINGDON, VA 24210

Report Date: 06/24/02
Lab Sample No.: **503172**
Client No.: 213
EMI Project No.: 162

Sample Identification: VA0090115

Date Collected: 05/28/02
Time Collected: 1425

Site Description: EVAPORATION OUTFALL

Sample Matrix: AQ
Collected By: B BUCHANAN

Parameter	Sample Result	Units	MDL	LOQ	Method	Date Analyzed	Time Analyzed	Analyst
Ammonia, Nitrogen	3.45	mg/l - N	0.040		4500-NH3 F	6/4/2002	1530	GSK
Chloride	7.00	mg/l	0.600		4500-C1B	5/31/2002	1340	TAY
Chlorine	BDL	mg/l	0.080		330.5	5/28/2002	1413	FLD
Cyanide, Total	BDL	ug/l	10.0		9010	6/10/2002	1040	GSK
Hardness	2.00	mg/l	2.00		130.2	5/31/2002	1415	TAY
MBAS	NEG	Pos/Neg			425.1	5/29/2002	1525	CS
Nitrate	0.430	mg/l	0.010		353.3&354.1	5/30/2002	829	CS
Sulfate	15.0	mg/l	1.00		375.4	6/3/2002	1110	TAY
Sulfide, Hydrogen	BDL	mg/l	2.00		EPA 376.1	5/31/2002	1600	GSK
Total Dissolved Solids	15.0	mg/l	6.00		160.1	5/31/2002	1345	AD

Flow if Available (GPM):
Temp. if Available (C):
Depth if Available (Ft):
Analysis Package Code: *+

Type of Sample: Grab
BDL = Below Detection Limit
FLD = Field Technician
SCSP

EMI PROFESSIONAL SERVICES

ENVIRONMENTAL MONITORING, INCORPORATED
ENVIRONMENTAL CONSULTANTS ▲ ANALYTICAL LABORATORIES
P.O. BOX 1477 ▲ COEBURN, VIRGINIA 24230 ▲ 276/395-3661

Certificate of Analysis

Client Name: VIRGINIA GAS COMPANY
Address: 200 EAST MAIN STREET
ABINGDON, VA 24210

Sample Identification: VA0090115

Site Description: EVAPORATION OUTFALL

Report Date: 06/24/02
Lab Sample No.: **503172**
Client No.: 213
EMI Project No.: 162
Date Collected: 05/28/02
Time Collected: 1425
Sample Matrix: AQ
Collected By: B BUCHANAN

Parameter	Sample Result	Units	MDL	LOQ	Method	Date Analyzed	Time Analyzed	Analyst
Antimony, Total	BDL	ug/l	1.80		7041	6/20/2002	911	CS
Arsenic, Total	BDL	ug/l	0.400		7060	6/18/2002	915	CS
Barium, Total	0.0020	mg/l	0.0010		6010	6/6/2002	1337	CS
Cadmium, Total	BDL	ug/l	0.200		7131	6/6/2002	1337	CS
Chromium, Hexavalent	BDL	mg/l	0.0020		7195	5/29/2002	1414	CS
Chromium, Total	BDL	mg/l	0.0010		6010	6/6/2002	1337	CS
Copper, Total	BDL	mg/l	0.0010		6010	6/6/2002	1337	CS
Iron, Total	0.020	mg/l	0.020		236.1	6/20/2002	1400	CS
Lead, Total	BDL	ug/l	0.200		7421	6/17/2002	831	CS
Manganese, Total	BDL	mg/l	0.020		243.1	6/20/2002	1705	SP
Mercury, Total	BDL	ug/l	0.100		7470	6/18/2002	1002	CS
Nickel, Total	BDL	mg/l	0.0010		6010	6/20/2002	1027	CS
Selenium, Total	BDL	mg/l	0.0010		6010	6/6/2002	1337	CS
Silver, Total	BDL	mg/l	0.0030		6010	6/6/2002	1337	CS
Zinc, Total	BDL	mg/l	0.0010		6010	6/6/2002	1337	CS
Xylene, Total	BDL	ppb	0.220		8021B	5/31/2002	1320	GSK

Flow if Avaliable (GPM):
Temp. if Available (C):
Depth if Available (Ft):
Analysis Package Code: *+

Type of Sample: Grab
BDL = Below Detection Limit
FLD = Field Technician
SCSP

Form 4
Attachment I
Formation Testing Program

The request to conduct a formation test for the Class I-1x wells is no longer necessary since the company does not intended on drilling any further Class I -1x injection / disposal wells.

For the existing brine wells being proposed for a Class III permit, the injection pressure for recirculation in existing wells CH-18, CH-22 and CH-23 will be the regulatory prescribed pressure gradient of 0.75 psi per foot for gas storage verses the weight of the under-saturated brine being circulated in. Using an average cavern well depth of 3,100 feet, the maximum wellhead injection pressure (Pmax) can be calculated as so:

Pmax = (0.75 – 0.440) 3,100'

Pmax = 961 psi

where:

Pmax = injection pressure at the well head in pounds per square inch

0.44 = The value of 0.44 is the pressure gradient of 10% brine, which is obtained by multiplying 1.019 by the pressure gradient of freshwater which is 0.433 psi/FT. The specific gravity of 10% brine is 1.019.

3100' = injection depth in feet.

Please note that the above formula is also used in several sections of 40 CFR – Chapter I – Part 147 for existing Class III wells that are authorized by rule in various other states.

Also note that the regulatory prescribed pressure gradient of 0.75 psi / foot was granted by the Virginia State Corporation Commission after reviewing a geo-technical report prepared by Dr. Gabriel Fernandez, Geo-technical Engineer, in March 2001. Dr. Fernandez concluded in his report that "*Based on the results obtained for the FE (Finite Element) analysis carried out in this study, and the adequate behavior observed in the present storage caverns it is recommended to perform the in-situ tightness test of the proposed storage caverns at an internal pressure equivalent to 0.75 psi/ft of depth. If the tightness test is satisfactory, a maximum cavern pressure corresponding to the 0.75 psi/ft of depth gradient can be implemented.*"

These existing wells were found to have between 800 – 1,000 psi at the surface before Virginia Gas begun the well work over construction (well re-entry) in 2000 to prepare the wells for gas injection and brine withdrawal. Please refer to Daily Work-over Reports included in Appendix C for reference of the discovery pressure on CH-23 during the initial re-entry. This discovery pressure is a strong indication that the wells and associated caverns are tight vessels and were in essence under a 28 year hydrostatic pressure test. Virginia Gas conducted re-circulation through these existing wells and caverns after re-entry for nine continuous months in 2002 via authorization by rule from EPA and did not experience any conditions during that operation that would negate or hinder future successful re-circulation or leaching operations in these existing wells. Once these wells are completed for use to inject gas into the storage caverns a nitrogen /

wells are completed for use to inject gas into the storage caverns a nitrogen / brine interface MIT test will be conducted using a 0.80 psi/ft of depth gradient to ensure operational stability.
For the three remaining proposed Class III injection wells not yet drilled, the wellhead injection pressure will be the sum of the differences in hydrostatic weights of water circulated in verses the weight of the saturated brine circulated out plus any pipe friction pressure, plus the hydrostatic pressure difference to discharge into one of the brine holding ponds via existing or future brine return pipelines.

Using an assumed cavern well depth of 4,200 feet the differences in hydrostatic weight would be calculated as follows:

0.468 psi/foot (saturated brine) x 4,200' = 1966 psi

0.433 psi/foot (fresh water) x 4,200' = 1819 psi.

1966 psi – 1819 psi = 147 psi difference in hydrostatic weights.

Friction pressure at the maximum fluid injection rate of 6.94 barrels per minute in 4.5" O.D. pipe would be:

17 psi pressure loss / 1000 feet of pipe (SPE Monograph on Hydraulic Fracturing) x 4.2 (thousands) = 71 psi.

Depending on the location of the proposed wells it will be necessary to overcome a hydrostatic pressure to discharge the circulated brine out to one of the three holding ponds through the existing or future brine return pipelines. Assuming a surface wellhead elevation of 2,100', based on the existing site topography, and using the highest known elevation of 2,294' on the existing brine return line the hydrostatic pressure to overcome would be:

2294'- 2100' = 194' x 0.468 psi/foot (saturated brine) = 90 psi.

Therefore, the calculated wellhead injection pressure for new leaching wells would be:

147 psi + (71 psi x 2) + 90 psi = 379 psi *

*The calculated wellhead injection pressure for new leaching wells is dependent on all of the assumed variables and could be 100 psi greater than calculated above. Once a suitable gas storage cavern is created from these new wells the wellhead injection pressure should coincide with the regulatory prescribed pressure gradient for gas storage. The regulatory prescribed pressure gradient would ultimately be decided by the Federal Energy Regulatory Commission or the Virginia State Corporation Commission and results of any MIT testing conducted prior to gas storage operations.

Form 4
Attachment J
Stimulation Program

A stimulation program is not applicable for these existing or proposed wells.

Form 4
Attachment K
Injection Procedures

Existing Wells CH-18, CH-22 and CH-23

The fluid to be injected is brine from 3 separate holding ponds (Pond A, Pond B, Pond C) located on the property and discharge water from the brine evaporation facility (Figure 3). The maximum distance from any pond to well (Pond A to Well CH-23) is approximately 4000 feet. The minimum distance from any pond to well (Pond C to Well CH-25) is approximately 1880 feet. The fluid from the brine ponds will be pumped or trucked to the wellhead and injected in order to maintain suitable feed brine for the evaporation plant and for cavern stability during natural gas displacement and for brine re-saturation. In the case of gallery CH-18/19/21/22/23, the brine will be pumped into CH-18 and removed through CH-22 or CH-23(See Figure 6). However, this process may need to be reversed from time to time in order to clean out any crystallization that may occur in the brine strings. The reversal process will entail injecting brine into the CH-22 and / or CH-23 and withdrawing from the CH-18 well. The transfer pump (Schlumberger/REDA, horizontal 36-stage centrifugal pump, pumping ~130 gpm at 700 psig) will pump the brine from the pond through an 8" pipeline, to the wellhead and then injected into the well(s). The rate of injection is expected to be relatively low at approximately 90-150 gpm during the winter season (November through March) for brine re-saturation and to conduct Mechanical Integrity Tests on gas storage caverns.

Proposed Wells

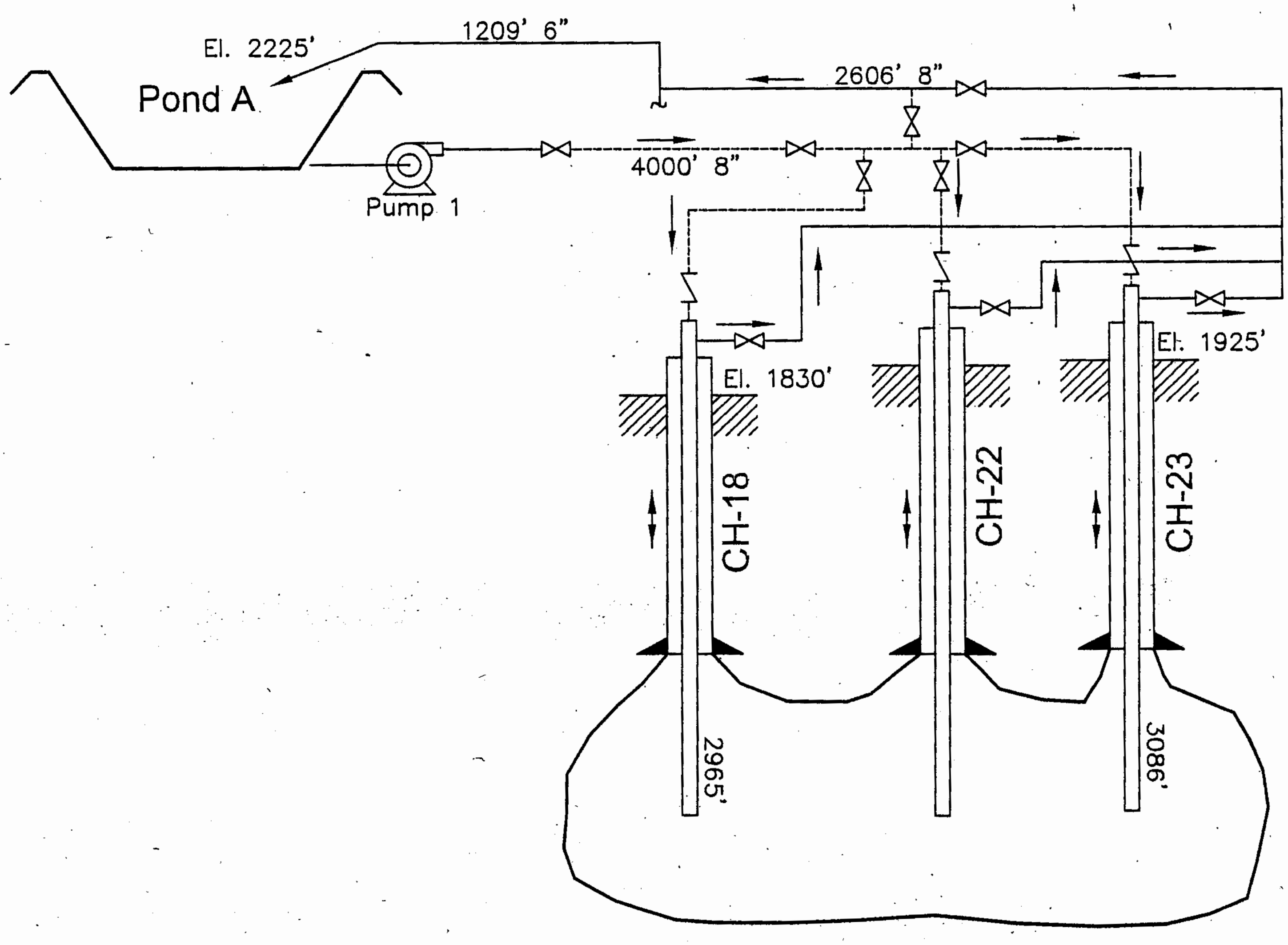
The injection procedure for the proposed wells currently permitted but not yet constructed has been modified from the previous application to include additional sources of water as high lighted in the following paragraph.

Fresh water will be withdrawn from water wells, **existing brine holding ponds, and (or) evaporator distillate**. Fresh water wells, if needed, will be drilled in close proximity to the proposed Class III wells and completed in the Upper Cambrian and Odovician dolomites. The water will be pumped through a pipeline and into the test holes which will be completed open hole. The fresh water will travel down into the 7" or 4.5" string of pipe and out into the open hole where leaching of the salt beds occur. As water dissolves the salt, a cavity will be created. Approximately 300,000 barrels of space will be leached per cavity to obtain 214,000 barrels of working gas storage. It has been estimated that ten barrels of water will be needed to leach one barrel of salt. Therefore, 3,000,000 barrels of water will be needed to create the 300,000 barrel cavity described above. The resulting brine will then be circulated back out of the well through the 4.5" work string. Return flow lines will then transport the fluid into the existing brine holding ponds. The caverns will be spaced approximately 800' to 1,000' or greater, apart to prevent their coalescence.

Injection of brine into Class I wells for disposal is no longer desired due to the construction and operation of the evaporation facility.

VIRGINIA GAS COMPANY
Typical Recirculation Diagram
10/14/03

Gallery CH-23/18
Recirculation Hydraulics
40 to 100 GPM
2 3/8" tubing or 4 1/2" Brine String
(with transfer pump)



Form 4
Attachment L
Construction Procedures

Existing Wells CH-18, 22 and 23

The existing wells included in this permit were drilled beginning in 1930 for salt production by Olin Matheson. In 1972, Olin's operations were closed and the wells were plugged by Fenix and Scisson. In the mid 1990's the wells were reevaluated for their potential in natural gas storage and brine injection. A plan was subsequently developed to convert the wells to gas storage and the wells were reentered and reconditioned in three phases. Some of the wells have been completely reconditioned while others are in different phases. Reconditioning of all the wells is expected to be completed by December 2007. Wells CH-18, CH-19, CH-21, CH-25, CH-26, CH-27, and CH-28 are complete; CH-22 and CH-23 are to be completed in late 2003 or early 2004.

Phase 1 consisted of drilling out the 2-3/8" tubing. A detailed list of how this was accomplished follows:

- A coiled tubing unit was used to drill the cement plug out of the 2-3/8" tubing.
- When hydraulic connection with the cavern was made the well was shut in and the wellhead pressure recorded. This provided the pressure gradient the cavern had built up to since being plugged. The shut in pressure for all galleries has been approximately 800 psig. This is equivalent to cavern gradients of around 0.85 psi/ft at the casing shoes.
- After all of the wells in the gallery were drilled out, brine was produced from one well and the produced brine volume metered. The metered brine volume and the drop in pressure allowed estimation of the cavern volume from brine compressibility.
- As the brine was produced from one well, wellhead pressures of adjacent wells were monitored to detect and confirm hydraulic connection.
- Cement bond logs were run in the tubing to determine cement behind the pipe to aid in the Phase 2 tubing removal steps.

Phase 2 consisted of removing the 2-3/8" tubing, the 5-1/2" casing, the bottom section of 9-5/8" casing, and cementing a new 7" production casing. A detailed list of how this was accomplished follows:

- A workover rig was rigged up with a power swivel unit and mud system.
- The 2-3/8" tubing was removed by washing over, cutting and pulling, and milling.
- The 5-1/2" casing was removed by washing over, cutting and pulling, and milling operations.
- Sonar was run through the 9-5/8" casing to determine the top of the cavern.
- The 9-5/8" casing was cut at or near the cavern roof and an open hole sonar run to determine the cavern interval.
- The 9-5/8" casing was cut in 15' to 20' sections and dropped into the cavern to expose a minimum of 200' of open borehole above the planned production casing shoe.
- An inflatable packer was set in the borehole and a 20' to 30' cement plug placed on top of the packer.

- Attempts were then made to squeeze cement behind the bottom of the 9-5/8" casing. This was done by perforating the 9-5/8" casing up the hole and setting a retrievable packer at the bottom of the casing. If circulation could be established a cement retainer was set and cement squeezed behind the pipe. If circulation could not be established the casing was perforated deeper and circulation tested again. If circulation could not be established in the second test, the annulus was considered tight and the conversion program continued.
- The casing head was installed on the 9-5/8" casing and the 7" production casing was run in the hole and cemented to surface. The well was then shut in for 72 hours to allow the cement to set. The production casing connections were internally tested as the casing was run.
- The casing test was conducted. The cement and casing show drilled out. The casing shoe was then tested to a 0.8 psi/ft gradient. See attached Cement Bond Log in Appendix C.
- The remainder of the cement was drilled out and the top of inflatable packer milled up and the body of the packer pushed down into the cavern.

Phase 3 consisted of installing the 4-1/2" dewatering casing and wellhead, and conducting the Mechanical Integrity Test (MIT). A detailed list of how this will be accomplished follows:

- The wellhead was installed and the 4-1/2" casing run in the hole to the top of the rubble in the cavern. The casing connections were externally tested as the casing was run. The 4-1/2" casing was run with a bit and float valve on the bottom to allow drilling. It was necessary to drill the 4-1/2" dewatering casing into the rubble since the bulk of cavern space is in the rubble. This allows brine to be dewatered from rubble for gas storage.
- The 4-1/2" casing was drilled into the rubble to the T.D. by rotating with a power swivel unit. The maximum depth drilled into the rubble pile was 403'.
- After drilling to T.D. the 4-1/2" casing was perforated above the bit and float to allow cavern dewatering.
- After the wells in the gallery are completed the cavern will be pressured up with brine and allowed to stabilize for the MIT.
- A nitrogen / brine interface mechanical integrity test will be conducted.
- Piping and valves will be installed and the wells will be prepared for gas storage and brine injection operations.

Proposed Cavern Wells

There are no modifications being made to the construction procedures for the proposed cavern wells that were previously permitted but not yet constructed.

Disposal Wells

There is no further future intent on drilling any more Class I disposal wells.

Form 4
Attachment M
Construction Details

Existing Wells (CH-18, 22 and 23)

Schematic drawings of the surface and subsurface construction details of the three wells are submitted for review in Appendix B.

1. CH-18 Well Schematic
2. CH-22 Well Schematic
3. CH-23 Well Schematic
4. Typical Surface Details of Temporary Wellheads
5. Typical Surface Details of Permanent Wellheads

Proposed Class III Wells

No change has been made to the construction details for the proposed wells that have not yet been drilled but are currently permitted.

Disposal Wells

There is no further future intent on drilling any more Class I disposal wells.

Form 4
Attachment N
Changes in Injected Fluid

1. Pressure Changes - The process of injecting fresh water and saturated brine water into the Class III-G wells will result in minor leaching of the formation and the dissolving of salts into the unsaturated fluid. The resulting specific gravity of the super saturated brine will be higher and will vary slightly causing small changes to occur in the circulating pressure.

   An analysis of the injected fluids is shown in Attachment H and identifies the proposed injection fluids to the brine from surface holding Ponds A, B, C (de-brined from the galleries for gas storage creation), and the distilled water discharged from the evaporation plant.

2. Changes in direction of movement - No changes in the direction of movement of the injected fluid are expected during the life of the well since all injected fluid will be circulated to surface.

3. Displacement of native fluids in the formation - The fluids currently present in the cavern well galleries were injected by a previous solution mining operation that occurred in the 1940's through the 1960's. The previously injected fluid and re-circulation fluid will be displaced to the surface holding ponds to be used as feed brine for the salt evaporation plant. A portion of the existing surface pond fluids will be combined with the distilled discharge water of the evaporation plant for re-circulation through the cavern galleries.

Form 6
Attachment O
Plans for Well Failures

In order to ensure the integrity of the cavern during the brine re-circulation and gas injection operation, annulus pressure between the 4-1/2" and 7" casing, between the 7" and 9-5/8" casings and between the 9-5/8" and 13-3/8" casings will be monitored and recorded with pressure gauges throughout the operation to assure no leakage. If any pressure build-up occurs, the brine re-injection process will be stopped. A continuous recording of injection flow rate, pressures, and the cumulative volumes injected will occur. The continuous recording will allow the detection of variances or failures within the well.

The injection wells, caverns, and associated facilities will be equipped with fail safe devices that will automatically shut down if high/low injection pressure is encountered. The high pressure shut down and the low pressure shut down settings shall be determined based upon daily injection operating pressures. If a significant pressure change occurs, injection operations will shut down and an investigation to determine the source of the pressure change will begin.

Upon completion of conversion to gas storage wells, each cavern wellhead will contain an Emergency Shutdown System (ESD). The ESD system will be designed in a manner that will allow it to be manually activated as well as remotely operated in the event of an emergency. The ESD system will be tested at least twice per year by manually tripping a relay or the manual valve. The sensors will be checked with nitrogen on an annual basis to verify their set point and ability operation.

Each wellhead's ESD system can be tripped in the following ways:

- Local trip station at the wellhead
- Remote trip station ~ 150' from each wellhead
- Remote trip from SCADA computer at compressor station control room
- High debrine pressure switch (pneumatic) at wellhead
- High backflush pressure switch (pneumatic) at wellhead
- High debrine and backflush pressures via pressure transmitter at wellhead communicating with SCADA computer at compressor station control room
- High gas pressure switch (pneumatic) at wellhead
- Low gas pressure switch (pneumatic) at wellhead
- High and low pressures via pressure transmitter at wellhead communicating with SCADA computer at compressor station control room
- High debrine flow rate from coriolis meter at wellhead
- Low brine density from coriolis meter at wellhead

If a leak is discovered in the wellbore equipment, the leak will be repaired as soon as possible. Injection operations will not resume until the wellbore equipment has been pressure tested successfully. If the problem cannot be readily corrected or immediate danger of migration exists, the pressure in the well will be reduced and stabilized. With the pressure stabilized, the well would be plugged as outlined in Attachment Q – Plugging and Abandonment Plan.

Form 6
Attachment P
Monitoring Program

No monitoring wells are proposed or planned in conjunction with this application. However, in order to ensure the integrity of the cavern during the brine re-circulation and gas injection operation, annulus pressure between the 2-3/8" and 5-1/2" casing, between the 5-1/2" and 9-5/8" casings and between the 9-5/8" and 13-3/8" casings will be monitored and recorded with pressure gages throughout the operation to assure no leakage. If any pressure build-up occurs, the brine re-injection process will be stopped. A continuous recording of injection flow rate, pressures, and the cumulative volumes injected will occur to detect variances or failures within the well. Prior to conducting these operations, a four method Subsidence Monitoring Plan was developed and further discussed below:

1. **Periodic Surface Level Surveys**. Virginia Gas will conduct periodic level surveys on a bi-yearly basis, one during early spring (late March or early April) after cavern activities have relaxed and one during the fall before the gas injection season begins (late October or early November) for the duration of the project. A map of the grid is included (Figure 7) and was compiled during the summer of 2000. Virginia Gas will keep these records on site and available at request. Virginia Gas will immediately notify the appropriate state and federal agencies should the results of any survey illustrate that any one point within the grid has settled more than one foot horizontally and or vertically. If the periodic level survey illustrates more than 2' of settlement vertically within 500' feet of any permanent structure or residence the company shall post an evacuation alert with the media, personally notify the immediate community (Elmwood and Smokey Row residents) and notify the agencies immediately.

2. **Gamma ray and caliper logging**. Virginia Gas will conduct gamma ray and caliper logging every two years for any high-pressure cavern that is active. Results will be kept on site for review at request.

3. **Sonar Survey of Caverns**. Virginia Gas will conduct sonar surveys every five years to depict the location and size of any active cavern and provide the results at request.

4. **Cavern Pressure Monitoring**. Virginia Gas will conduct daily pressure monitoring on any active cavern. Injection pressures flow rates and gas volumes will be monitored and recorded according to EPA monitoring requirements. The results shall be maintained on site for review at request.

If results of these surveys illustrate any type of cavern structural instability Virginia Gas will immediately begin decreasing cavern pressure and cease gas or brine injection operations. Company personnel will be placed on evacuation call if needed and a team of consultants and experts shall be transported to the site to perform an evaluation and compile a report of the occurrence, which will be made available to the appropriate agencies within one week.

Cavern and roof shape on all proposed Class III wells will be controlled during solution mining by a hydrocarbon blanket in the 7" x 9-5/8" annulus, the water injection rates, and the water injection and brine removal locations which will be controlled by up or down movement of the 7" x 4-1/2" work strings. The roof cavern will not be allowed to develop above the lowest depth of the 9-5/8" casing. This should allow a minimum vertical separation of 1,800' - 2,000' from the above adjacent formations. Monitoring of the cavern roof shape will be obtained during development by (1) periodic verification of the location of the hydrocarbon blanket; (2) monitoring of the total volume of salt removed from the cavern; and (3) sonar surveying of the cavern.

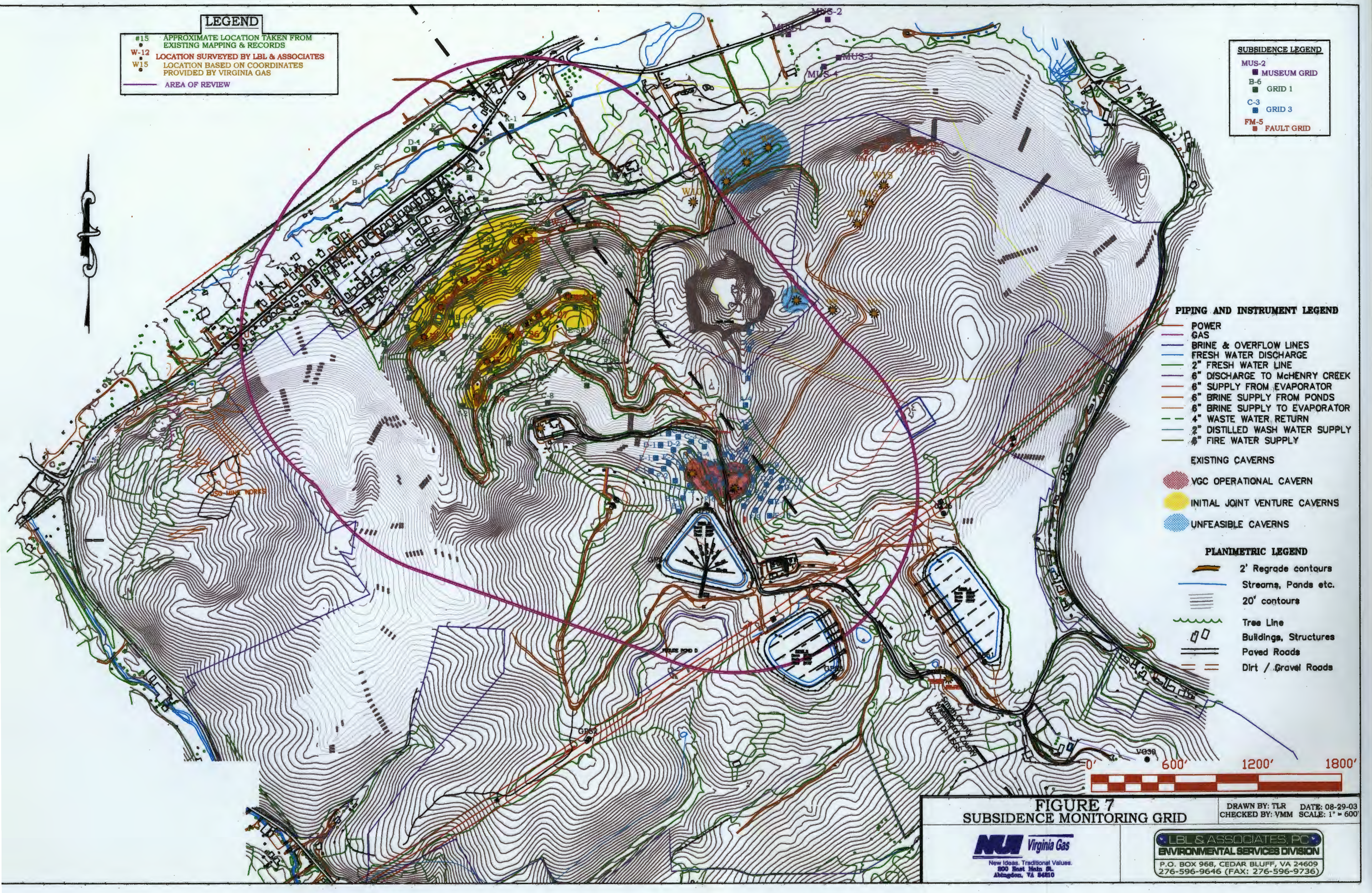


FIGURE 7
SUBSIDENCE MONITORING GRID

Form 6
Attachment Q
Plugging and Abandonment Plan

See the attached EPA Form 7520-14, Plugging and Abandonment Plan and Figure 8 for the Typical Plugging Schematic referenced to Well CH-18 for data purposes only.

Well CH-18 Specifications:
- 13 3/8" casing – 1,321' (cemented to the surface)
- 10 3/4" casing – cut at 2,278'
- 7" casing – 2,463' (cemented to surface)
- Top of the cavern ~ 2,574'
- Top of rubble ~ 2,622'
- 4 ½" casing – 2,965'

The plugging and abandonment plan for the wells is preliminary at this time but a general plan includes doing the following:

1. Move in service rig and cementing equipment.
2. Run in hole and cut 4 ½" casing at top of rubble.
3. Trip out and lay down 4 ½" casing string.
4. Run in hole with 7" cast iron bridge; set bridge plug near bottom of 7" casing (2463').
5. Run in hole with tubing to bridge plug. Mix and pump 54.3 bbl of 6% bentonite gel (Fill up from 2173' to 1321') and 11.9 bbl of Class A cement with 2% CaCl (= 500 gal =66.85cuft = 48 sacks) (cement fill up from 2463' to 2163'). Displace cement. Pull tubing up to 1321'. Set cast iron bridge plug at 1321'.
6. Mix and pump 34.9 bbl of 6% bentonite gel (Fill up from 1121 to 200'). Mix and pump 7.9 bbl of Class A cement with 2% CaCl (cement fill up from 1321' to 1121'). Displace cement. Pull tubing up to 200'. Set cast iron bridge plug at 200'
7. Mix and pump 7.9 bbl of Class A cement with 2% CaCl (cement fill up from 200' to surface). Pull tubing out of the hole. Rig down equipment; reclaim site.

   Note: Setting a cement plug inside the 7" at the 16" and 20" depths would be irrelevant because it has been isolated by the cemented 13 3/8" casing string when the wells were drilled over 30 years ago.

   Note: All volumes and depths are estimates. Actual volumes and depths may change as field conditions warrant.

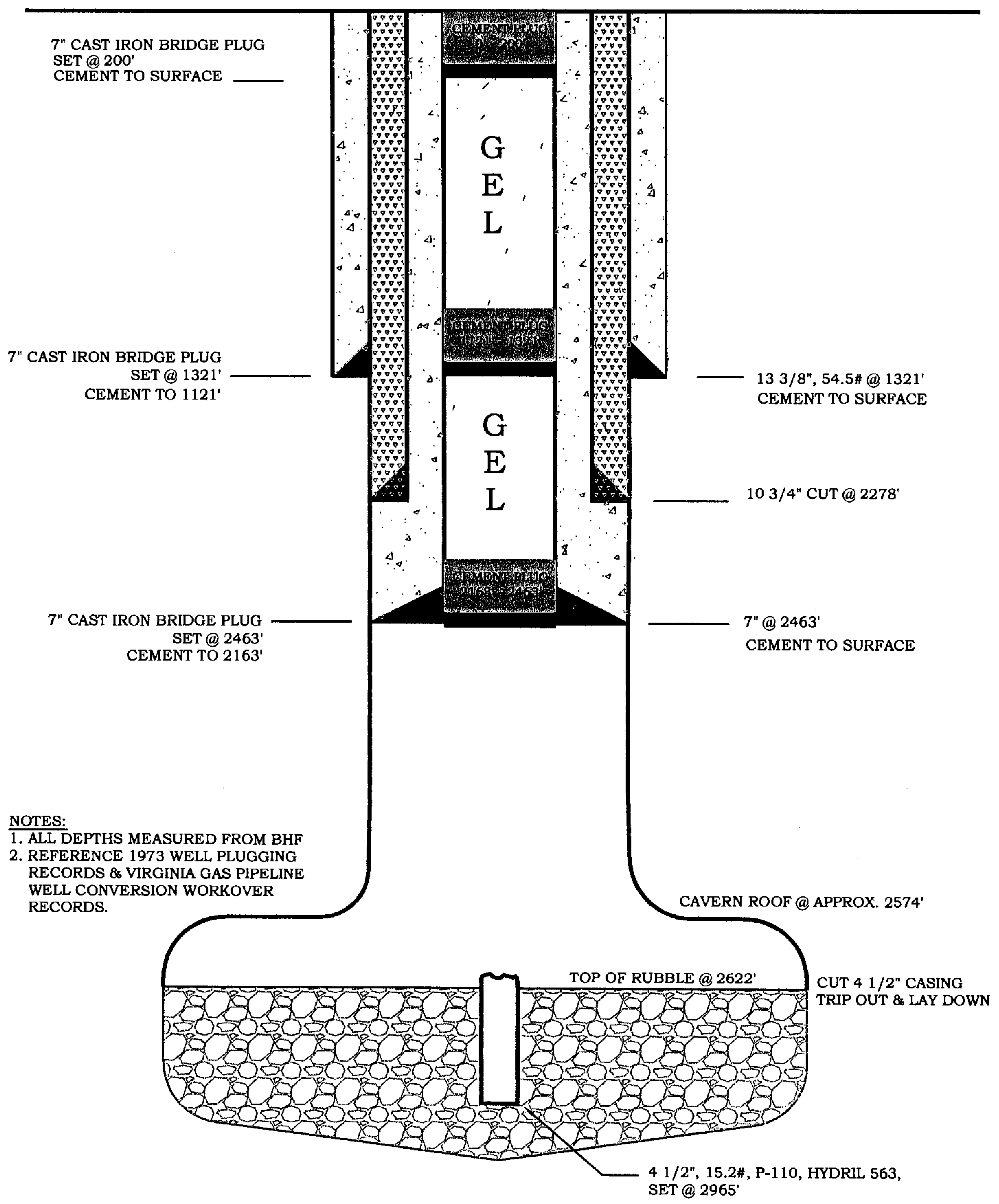


FIGURE 8

TYPICAL CLASS III WELL PLUGGING SCHEMATIC

DATA FOR THIS SCHEMATIC IS REFERENCED TO CH-18

DRAWN BY: BLB
CHECKED BY: GSH

DATE: 11-11-03
NOT TO SCALE

NUI Virginia Gas
New Ideas. Traditional Values.
200 East Main St.
Abingdon, VA 24210

LBL & ASSOCIATES, PC
ENVIRONMENTAL SERVICES DIVISION
P.O. BOX 968, CEDAR BLUFF, VA 24609
276-596-9646 (FAX: 276-596-9736)

Insert Financial Statement
Surety Bond,etc.

An existing bond is in place under the current permit and was provided in the previous application to provide the necessary resources to plug six wells.

Form 4
Attachment S
Aquifer Exemptions

An Aquifer Exemption has not been requested.

Form 6
Attachment T
Existing EPA Permits

EPA Permit # VAS1X932BSMY - An Area Permit for 3 Class 1X Injection Wells effective April 29, 1996 and remains in effect until April 29, 2006. To date, only one Class I well has been drilled which was plugged in October 2002. There are no further intentions of drilling additional Class I wells.

EPA Permit # VAS3G931BSMY - An Area Permit for 3 Class IIIG Injection Wells effective April 29, 1996 and remains in effect for the operational life of the facility.

Form 6
Attachment U
Description of Business

This permit is being filed in the name of Virginia Gas Pipeline Company as operating manager for the LLC. The Saltville Gas Storage Company, LLC, a partnership between Virginia Gas Pipeline Company and Duke Energy Gas Transmission, is developing a natural gas storage field in conjunction with a brine removal / recirculation operation in Saltville, Virginia.

Virginia Gas Company was founded in 1987 as a privately held Delaware Corporation. Today it is part of NUI Corporation based in Bedminster, New Jersey. NUI Virginia Gas is engaged in natural gas storage, pipeline operations and natural gas distribution all of which are in the Commonwealth of Virginia. NUI also operates businesses involved in natural gas exploration, wholesale energy trading and portfolio management, retail energy sales, energy and environmental project development, energy consulting, sales outsourcing, telecommunications, and geospatial and customer information systems and services.

Houston-based Duke Energy Gas Transmission owns and operates 12,000 miles of interstate natural gas pipelines known as Texas Eastern Transmission, LP; Algonquin Gas Transmission Co.; East Tennessee Natural Gas Co.; and partially owns Maritimes & Northeast Pipeline and the proposed Gulfstream Natural Gas System. Duke Energy, a diversified multinational energy company, manages a dynamic portfolio of natural gas and electric supply, delivery and trading businesses. Duke Energy is headquartered in Charlotte, N.C.

The LLC owns the majority of the salt cavern natural gas storage facility in Saltville, Virginia. The salt caverns offer potential for fast-injection and fast-withdrawal capabilities, which make it ideal for supplying natural gas to electric generation plants. It is located near a number of existing and planned interstate gas pipelines and power generation plants. The agreement calls for expansion of the storage facility from its current capacity of 1.1 billion cubic feet (Bcf) up to 10 Bcf and its connection to Duke Energy Gas Transmission's East Tennessee Natural Gas mainline system. At full capacity, the Saltville storage field will be able to deliver up to 500 million cubic feet of natural gas per day to area markets.

Another component of development of the Saltville storage field is the brine disposal process. As the salt caverns are developed for natural gas storage, existing salt brine is displaced to the surface. In 1999 an evaporator plant was built to assist in the disposal of the brine and by 2000 the company was selling salt to agricultural markets. Due to the recent and on going expansion of the gas storage facility the company is also enlarging the existing evaporation facility by constructing a new evaporation plant with the capability of processing up to 400-gpm of displaced brine. The facility is the only salt producer in the mid-Atlantic region and has received FDA food grade certification.

APPENDICES

APPENDIX A
Lithologic Data Available

HIGH PRESSURE BRINE WELL NO. 18

ELEV. 1830

Club House Hollow

From	To	Feet	
0	225	225	Red Shale
225	245	20	Red & Gray Shale
245	255	10	Gray Shale & Plaster
255	281	26	Red & Gray Shale
281	284	3	Gray Shale
284	302	18	Gray Limestone
302	306	4	Black Limestone
306	308	2	Gray Rock & Gray Mud
308	318	10	Gray Limestone
318	330	12	Sandy Limestone
330	333	3	No Drillings
333	340	7	Gray Shale
340	342	2	Gray Limestone
342	345	3	Gray Shale
345	355	10	Gray Shale (Trace of Salt) Plaster
355	374	19	Gray Limestone
374	384	10	Gray Shale & Salt 99%
384	506	122	Gray Shale
506	516	10	Sandy Limestone
516	525	9	Sandy Limestone & Salt 80%
525	530	5	" " " " 20%
530	539	9	" " " " 95%
539	557	18	Gray Shale
557	565	8	Gray Shale and Salt 80%
565	568	3	" " " " 90%
568	580	12	Salt 100%
580	585	5	" " " " 85%
585	600	15	" " " " 95%
600	610	10	" " " " 5%
610	698	88	Gray Shale
698	708	10	Gray Shale and Salt 40%
708	728	20	" " " " 95%
728	740	12	" " " " 80%
740	750	10	" " " " 70%
750	760	10	" " " " 80%
760	766	6	" " " " 20%
766	776	10	" " " " 50%
776	785	9	" " " " 10%
785	1136	351	Gray shale
1136	1145	9	" " " 30%
1145	1178	33	Gray Shale
1178	1184	6	" " " 40%
1184	1194	10	Gray Shale
1194	1204	10	" " " 100%
1204	1214	10	Salt 95%
1214	1221	7	" 80%
1221	1225	4	" 50%
1225	1245	20	Gray Shale
1245	1265	20	" " " 10%
1265	1290	25	Gray Shale
1290	1300	10	" " " 80%
1300	1334	34	" " " 95%

Sheet #2

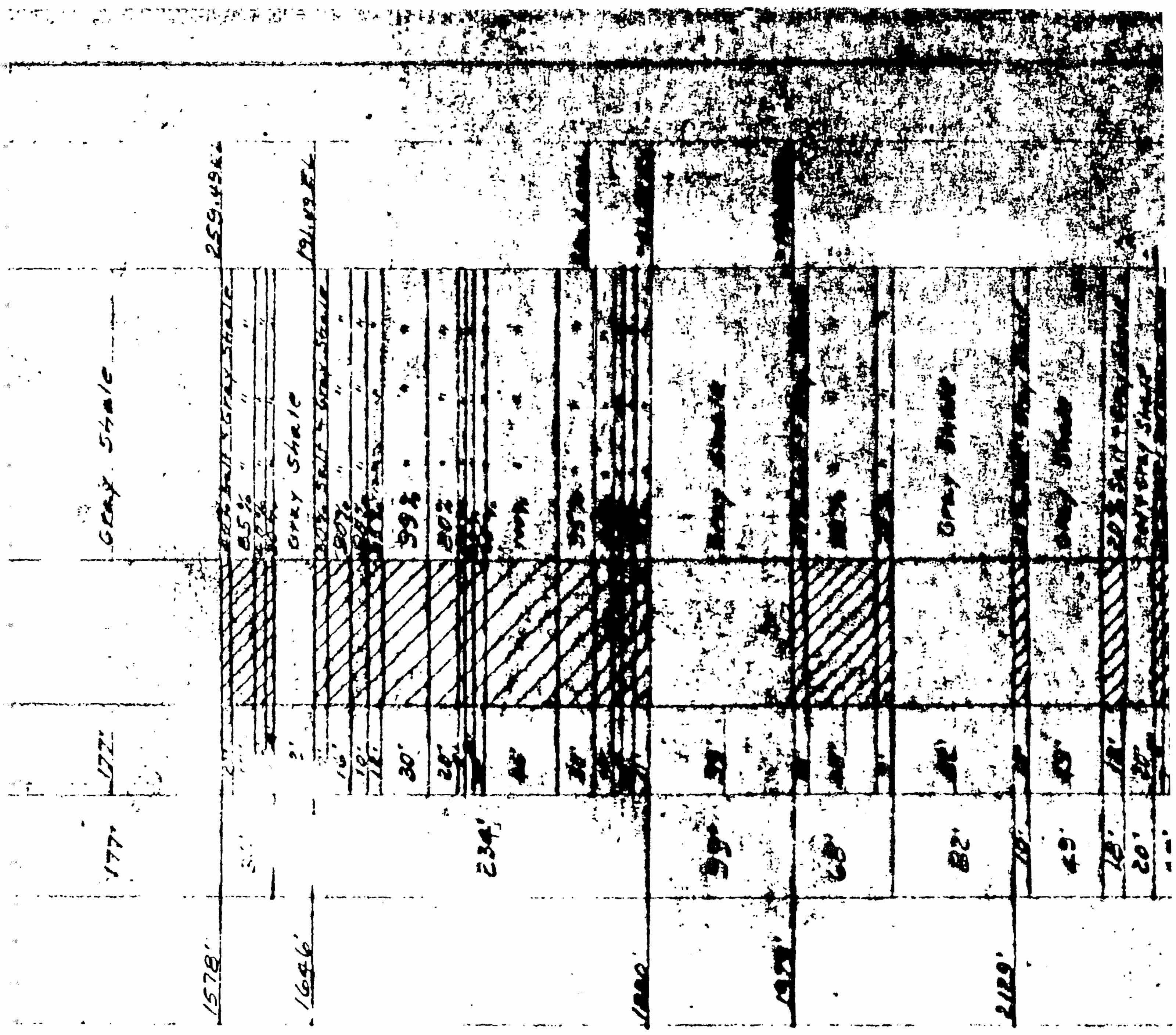
HIGH PRESSURE BRINE WELL NO. 18

Club House Hollow

From	To	Feet		
1334	1345	11	Gray Shale	Salt 70%
1345	1390	45		" 95%
1390	1395	5		" 100%
1395	1401	6		" 60%
1401	1578	177	Gray Shale	
1578	1586	8	" "	" 40%
1586	1604	18		" 85%
1604	1610	6		" 40%
1610	1614	4		" 30%
1614	1646	32	Gray Shale	
1646	1656	10	" "	" 30%
1656	1672	16		" 90%
1672	1682	10		" 80%
1682	1694	12		" 95%
1694	1724	30		" 99%
1724	1744	20		" 80%
1744	1749	5		" 50%
1749	1757	8		" 99%
1757	1767	10		" 95%
1767	1813	46		" 100%
1813	1843	30		" 95%
1843	1853	10		" 80%
1853	1859	6		" 95%
1859	1869	10		" 100%
1869	1880	11		" 70%
1880			Gray Shale	

See Drip T.D. 3010

CH-18



CH-18

19'	10'	20'	[illegible] + Gray Shale	
	45'	45'	Gray Shale	
	18'	18'	20% Salt + Gray Shale	
	20'	20'	Red + Gray Shale	
	28'	18'	[illegible]	
	126'	126'	Gray Shale	
2380'	22'	10'	5% Salt + Gray Shale	-562.51 Elev
		12'	40% " "	
	32'	32'	Gray Shale	-596.51
	14'	[illegible]	40% Salt + Gray Shale	
		[illegible]	55%	
	182'	182'	Gray Shale	
2630'	20'	14'	40% Salt + Gray Shale	
	74'	21'	Gray Shale + Gypsum	
		55'	Gray Shale	
	19'	9'	25% Salt + Gray Shale	
		10'	55%	
	97'	57'	Gray Shale	
		20'	Red + Gray Shale	
		20'	Gray Shale	
	71'	71'	Red + Gray Shale	
[illegible] 2817				

10 3/4 casing

HIGH PRESSURE BRINE WELL #21

Started drilling July 8, 1960 - Completed drilling Feb. 3, 1961

From	To	Feet		
0	30	30	Red Shale	
30	39	9	Red and Gray Shale	
39	49	10	Gray Shale	
49	159	110	Red Shale	
159	189	30	Gray Shale	
189	252	63	Red Shale	
252	268	16	Red and Gray Shale	
268	305	37	Gray Shale	
305	333	28	Gray Shale and Gypsum	
333	403	70	Red Shale	
403	434	31	Gray Shale	
434	437	3	Gray Shale and Salt	20%
437	458	21	" " " "	60%
458	475	17	Gray Shale	
475	485	10	Gray Shale and Salt	75%
485	515	30	" " " "	85%
515	541	26	Gray Shale	
541	548	7	Gray Shale and Salt	20%
548	555	7	Gray Shale with Mud	
555	565	10	Gray Shale and Salt	90%
565	571	6	Gray Shale	
571	577	6	Gray Shale and Salt	90%
577	581	4	Gray Shale	
581	591	10	Gray Shale and Salt	90%
591	606	15	" " " "	95%
606	610	4	" " " "	30%
610	619	9	" " " "	10%
619	642	33	Gray Shale	
642	649	7	Gray Shale and Salt	10%
649	659	10	" " " "	95%
659	675	16	" " " "	98%
675	680	5	" " " "	95%
680	685	5	" " " "	75%
685	690	5	" " " "	25%
690	700	10	" " " "	80%
700	708	8	" " " "	85%
708	714	6	" " " "	90%
714	730	16	" " " "	50%
730	740	10	" " " "	30%
740	746	6	" " " "	75%
746	751	5	" " " "	90%
751	757	6	" " " "	95%
757	768	11	" " " "	10%
768	778	10	" " " "	50%
778	782	4	" " " "	70%
782	787	5	" " " "	90%
787	797	10	" " " "	40%
797	806	9	" " " "	75%
806	827	21	" " " "	95%
827	835	8	" " " "	85%
835	840	5	" " " "	40%

HIGH PRESSURE BRINE WELL # 21

	From	To	Feet		
	840	890	50	Gray Shale	
	890	895	5	Gray Shale and Salt	40%
Reduced Hole 20" to	895	1015	120	Gray Shale	
16" (940')	1015	1021	6	Gray Shale and Salt	80%
	1021	1043	22	Gray Shale	
	1043	1050	7	Gray Shale and Salt	20%
	1050	1060	10	" " " "	95%
	1060	1068	8	" " " "	80%
	1068	1075	7	" " " "	60%
	1075	1082	7	" " " "	95%
	1082	1087	5	" " " "	80%
	1087	1181	94	Gray Shale	
	1181	1186	5	Gray Shale and Salt	40%
	1186	1200	14	" " " "	99%
	1200	1207	7	" " " "	40%
	1207	1299	92	Gray Shale	
	1299	1306	7	Gray Shale and Salt	75%
	1306	1313	7	" " " "	95%
	1313	1327	14	" " " "	80%
	1327	1332	5	" " " "	95%
	1332	1342	10	" " " "	75%
	1342	1353	11	" " " "	50%
	1353	1361	8	" " " "	95%
	1361	1369	8	" " " "	99%
	1369	1379	10	" " " "	50%
	1379	1387	8	" " " "	80%
	1387	1407	10	" " " "	99%
	1407	1419	12	" " " "	95%
	1419	1432	13	" " " "	85%
	1432	1442	10	" " " "	95%
Reduced Hole to 12"	1442	1450	8	" " " "	99%
@ 1450'	1450	1462	12	" " " "	10%
	1462	1638	176	Gray Shale	
	1638	1645	7	Gray Shale and Salt	80%
	1645	1655	10	" " " "	98%
	1655	1672	17	" " " "	90%
	1672	1701	29	" " " "	99%
	1701	1727	26	Gray Shale	
	1727	1733	6	Gray Shale and Salt	70%
	1733	1742	9	" " " "	30%
	1742	1838	96	Gray Shale	
	1838	1852	14	Gray Shale and Salt	80%
	1852	1859	7	" " " "	30%
	1859	1868	9	" " " "	90%
	1868	1881	13	" " " "	50%
	1881	1900	9	" " " "	15%
	1900	1943	43	Gray Shale	
	1943	1952	9	Gray Shale and Salt	15%
	1952	1958	6	" " " "	50%
	1958	1968	10	" " " "	75%
	1968	1979	11	" " " "	90%
	1979	1988	9	" " " "	10%
	1988	2068	80	Gray Shale	
	2068	2082	14	Gray Shale and Salt	50%

Sheet # 3. HIGH PRESSURE BRINE WELL # 21

From	To	Feet		
2082	2087	5	Gray Shale and Salt	90%
2087	2094	7	" " " "	95%
2094	2224	130	Gray Shale	
2224	2231	7	Gray Shale and Salt	10%
2231	2236	5	" " " "	90%
2236	2244	8	" " " "	75%
2244	2264	20	" " " "	40%
2264	2270	6	" " " "	50%
2270	2299	29	" " " "	95%
2299	2307	8	" " " "	90%
2307	2317	10	" " " "	10%
2317	2355	38	Gray Shale	
2355	2365	10	Gray Shale and Salt	80%
2365	2375	10	" " " "	90%
2375	2385	10	" " " "	99%
2385	2390	5	" " " "	50%
2390	2450	60	" " " "	95%
2450	2452	2	" " " "	99%
2452	2459	7	" " " "	80%
2459	2465	6	" " " "	60%
2465	2472	7	" " " "	40%
2472	2483	11	" " " "	95%
2483	2626	143	Gray Shale	
2626	2636	10	Gray Shale and Salt	20%
2636	2644	8	Gray and Red Shale	
2644	2654	10	Red Shale	
2654	2664	10	Red and Gray Shale	
2664	2674	10	Gray and Red Shale Salt	10%
2674	2683	9	" " " " "	20%
2683	2695	12	" " " " "	40%
2695	2705	10	" " " " "	20%
2705	2747	42	Gray Shale	
2747	2755	8	Gray Shale and Salt	50%
2755	2766	11	" " " "	80%
2766	2786	20	" " " "	90%
2786	2796	10	" " " "	10%
2796	2814	18	Gray and Red Shale	
2814	2830	16	Gray and Red Shale Salt	25%
2830	2866	36	Gray Shale	
2866	2889	23	Gray Shale and Salt	50%
2889	2912	23	Gray and Red Shale	
2912	2929	17	Gray and Red Shale Salt	90%
2929	2942	13	" " " " "	80%
2942	2965	23	Gray Shale and Salt	40%
2965	2975	10	" " " "	90%
2975	2984	9	" " " "	99%
2984	2993	9	" " " "	90%
2993	3015	22	" " " "	50%
3015	3028	13	" " " "	75%
3028	3075	47	Gray Shale and Gypsum	
3075	3084	9	Gray Shale Gypsum Salt	50%
3084	3093	9	" " " "	20%

HIGH PRESSURE BRINE WELL # 21

From	To	Feet	
3093	3103	10	Gray Shale Gypsum and Salt 80%
3103	3107	4	Sandstone

Total Depth 3107 feet

Pipe used - Set up

	NO. lengths	
20" Cemented	17	533'- 10½" - 801 Bags Cement used
13 3/8"	42	1322'- 6¼"
9 5/8"	97	2926'- 3 3/4"
5½"	92	3027'- 3"
2"	98	3029'- 8"

Elev. 1890 Est

HIGH PRESSURE BRINE WELL No. 22

Started Drilling July 10, 1961 Finished Drilling Oct. 27, 1961

	From	To	Feet		
	o	20	20	Red Shale	
	20	53	33	Gray Shale	
	53	75	22	Red Shale	
	75	85	10	Gray Limestone and Red Shale	
	85	230	145	Red and Gray Shale	
	230	240	10	Gray Shale	
	240	250	10	Red "	
	250	268	18	Gray "	
	268	297	29	Red "	
	297	307	10	Gray Shale and Plaster	
	307	391	84	Red Shale	
	391	430	39	Gray "	
	430	450	20	Red "	
	450	460	10	Gray "	
	460	464	4	Gray Shale and Salt	10%
	464	482	18	" " " "	50%
	482	490	8	Gray Shale	
	490	498	8	Gray Shale and Salt	50%
	498	502	4	" " " "	95%
	502	522	20	" " " "	20%
	522	542	20	Gray Shale	
	542	562	20	Red and Gray Shale	
	562	567	5	Gray Shale and Salt	20%
Set up 16"	567	587	20	Gray Shale	
576' - 7"	587	607	20	Gray Shale and Salt	75%
	607	614	7	" " " "	95%
	614	619	5	" " " "	30%
	619	628	9	Gray Shale	
	628	634	6	Gray Shale and Salt	25%
	634	664	30	" " " "	50%
	664	678	14	" " " "	95%
	678	684	6	Gray and Red S "	20%
	684	691	7	Gray Shale and "	50%
	691	701	10	" " " "	90%
	701	711	10	" " " "	40%
	711	721	10	" " " "	70%
	721	781	60	Gray Shale	
	781	790	9	Gray Shale and "	20%
	790	795	5	" " " "	75%
	795	851	56	" " " "	90%
	851	857	6	" " " "	50%
	857	866	9	" " " "	20%
	866	872	6	" " " "	80%
	872	1106	234	Gray Shale	
	1106	1114	8	Gray Shale and "	50%
Cement 292 bags	1114	1119	5	" " " "	80%
13 3/8" 1121' 6½"	1119	1146	27	" " " "	95%
	1146	1212	66	" " " "	99%
	1212	1220	8	" " " "	60%
	1220	1229	9	" " " "	75%
	1229	1255	26	" " " "	99%
	1255	1263	8	" " " "	10%

HIGH PRESSURE BRINE WELL No. 22

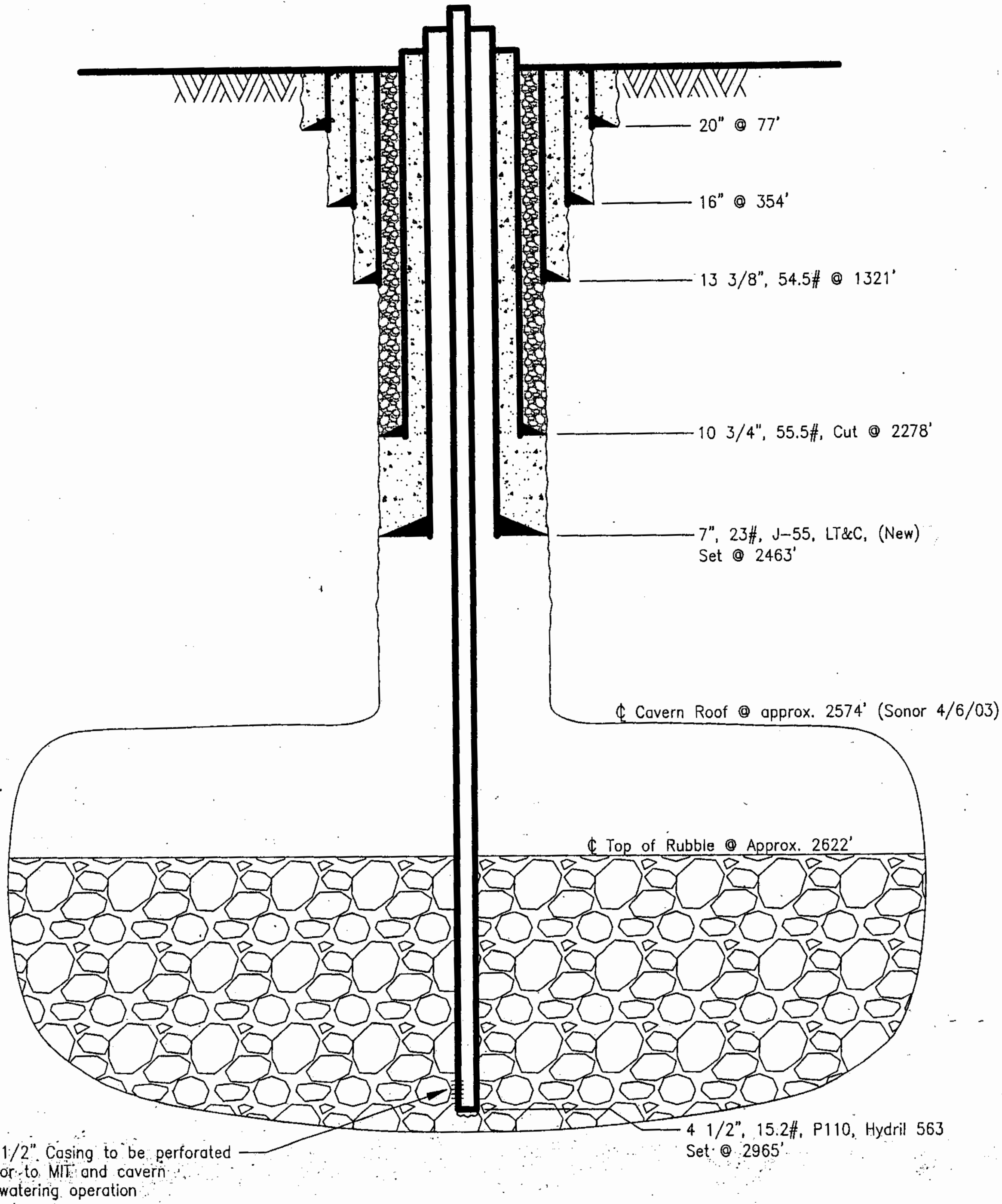
	From	To	Feet		
	1263	1397	134	Gray Shale	
	1397	1406	9	Gray Shale and Salt	50%
	1406	1415	9	" " " "	80%
	1415	1471	56	Gray Shale	
	1471	1491	20	Gray Shale and Salt	50%
	1491	1568	77	Gray Shale	
	1568	1598	30	Gray Shale with trace salt	
	1598	1833	235	Gray Shale	
	1833	1840	7	Gray Shale and Salt	20%
	1840	1848	8	" " " "	75%
	1848	1857	9	" " " "	95%
	1857	1869	12	" " " "	75%
	1869	1879	10	" " " "	40%
	1879	1900	21	" " " "	80%
	1900	1915	15	Gray Shale	
	1915	1933	18	Gray Shale and Salt	70%
	1933	1943	10	" " " "	40%
	1943	1990	47	Gray Shale	
	1990	2000	10	Gray Shale and "	40%
	2000	2040	40	" " " "	90%
	2040	2080	40	" Red " " "	20%
	2080	2085	5	" " " " "	5%
	2085	2098	13	Gray and Red Shale	
	2098	2118	20	Gray and Red Shale S	50%
	2118	2131	13	" " " " "	5%
	2131	2140	9	" " " " "	20%
	2140	2160	20	Gray and Red Shale	
	2160	2165	5	Gray and Red Shale "	20%
	2165	2170	5	" " " " "	50%
	2170	2176	6	" " " " "	75%
	2176	2186	10	Gray and Red Shale	
	2186	2195	9	Gray and Red Shale "	25%
Reduced Hole	2195	2205	10	Gray and Red Shale	
15 1/8- 12½"	2205	2218	13	Gray and Red Shale "	15%
	2218	2225	7	Gray and Red Shale	
	2225	2232	7	Gray and Red Shale "	30%
	2232	2275	43	Gray and Red Shale	
	2275	2318	43	Gray Shale	
	2318	2331	13	Gray Shale and "	70%
	2331	2380	49	Gray Shale	
	2380	2390	10	Gray Shale and "	20%
	2390	2400	10	" " " "	50%
	2400	2407	7	" " " "	96%
	2407	2436	29	" " " "	90%
	2436	2467	31	Gray Shale	
	2467	2480	13	Gray Shale and "	25%
	2480	2570	90	Gray Shale	
	2570	2590	20	Gray Shale and "	20%
	2590	2602	12	" " " "	50%
	2602	2644	42	Gray Shale	
	2644	2664	20	Gray Shale and "	60%
	2664	2684	20	" " " "	80%
	2684	2690	6	" " " "	50%
	2690	2695	5	" " " "	10%
	2695	2705	10	" " " "	75%

Sheet # 3. HIGH PRESSURE BRINE WELL No. 22

From	To	Feet					
2705	2730	25	Gray	Shale	and	Salt	90%
2730	2750	20	Gray	Shale			
2750	2758	8	Gray	Shale	and	"	20%
2758	2763	5	"	"	"	"	50%
2763	2773	10	"	"	"	"	10%
2773	2777	4	"	"	"	"	90%
2777	2792	15	"	"	"	"	20%
2792	2802	10	"	"	"	"	5%
2802	2811	9	Gray	Shale			
2811	2821	10	Gray	Shale	"	"	20%
2821	2830	9	"	"	"	"	75%
2830	2840	10	"	"	"	"	95%
2840	2855	15	"	"	"	"	85%
2855	2865	10	"	"	"	"	95%
2865	2889	24	"	"	"	"	50%
2889	2897	8	"	"	"	"	20%
2897	2927	30	Gray	Shale			
2927	2951	24	Gray	and Red	Shale		
2951	2982	31	Gray	Shale	and	"	40%
2982	2992	10	"	"	"	"	20%
2992	3008	16	Gray	and Red	Shale		
3008	3016	8	Gray	Shale	and	"	50%
3016	3023	7	"	"	"	"	95%
3023	3064	41	"	"	"	"	75%
3064	3074	10	"	"	"	"	99%
3074	3092	18	"	"	"	"	90%
3092	3105	13	"	"	"	"	60%
3105	3114	9	"	"	"	"	10%
3114	3127	13	Gray	and Red	Shale		
3127	3169	42	Gray	Shale	Gypsum		
3169	3181	12	Gray	Shale	and	"	80%
3181	3188	7	"	"	"	"	90%
3188	3190	2	Sand	Stone			

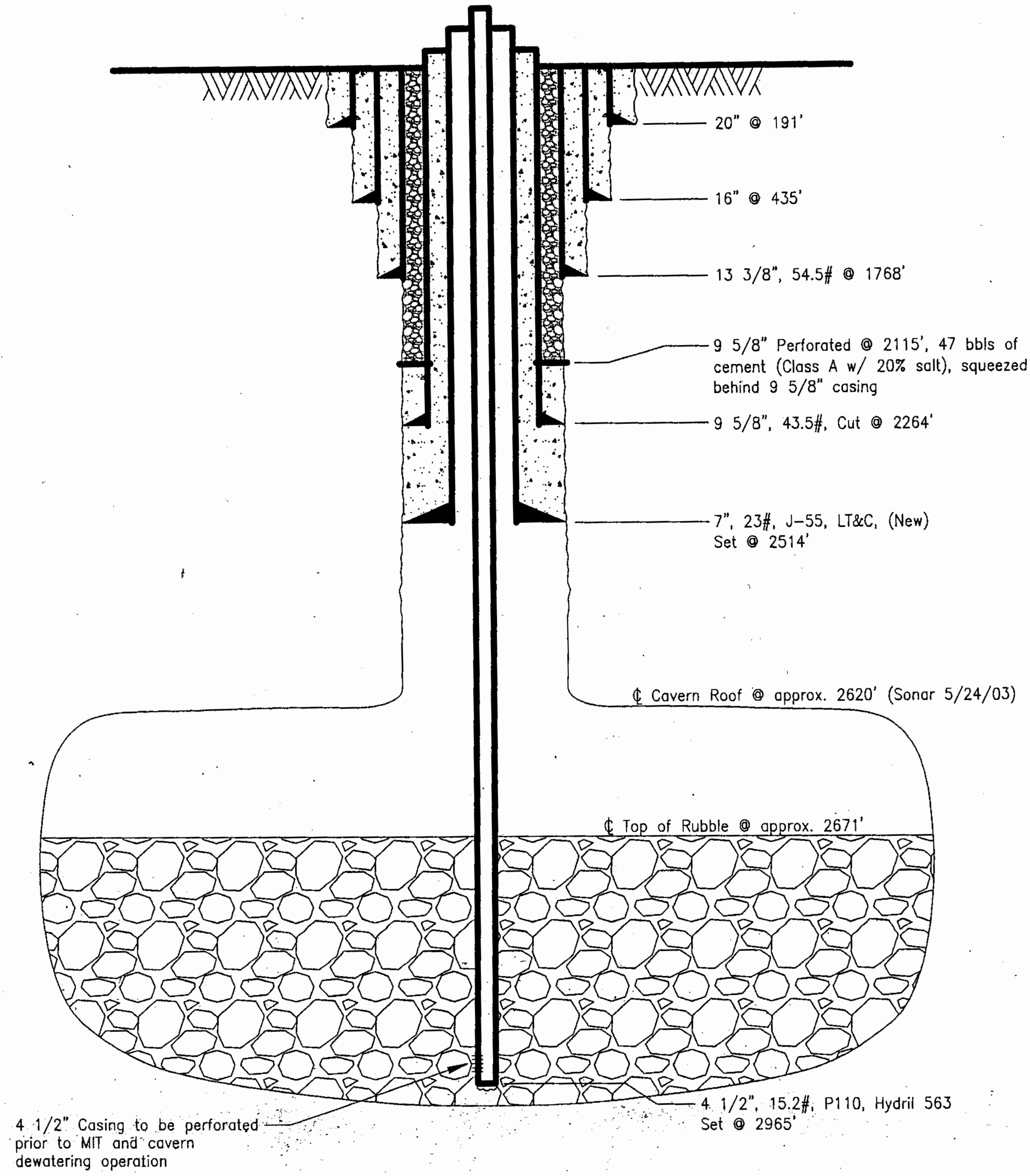
Total Depth -------- 3190 Feet

APPENDIX B
Well Schematics



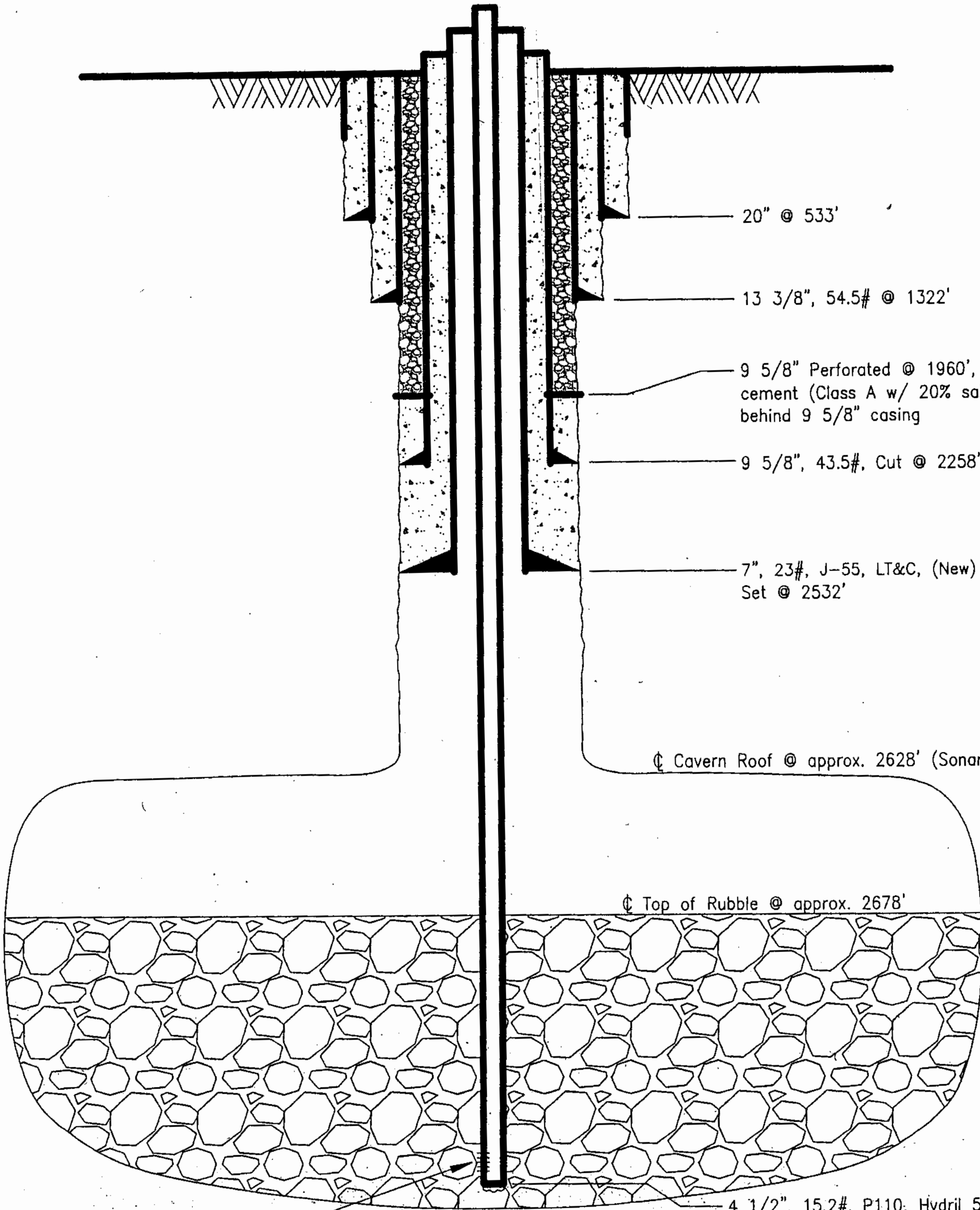
depths measured from BHF.
erence 1973 well plugging records and Virginia
Pipeline well conversion workover records.

Energy Storage Services, Inc. Engineering Construction Operations 11757 KATY FREEWAY #600 HOUSTON, TEXAS 77079			SALTVILLE GAS STORAGE COMPANY, LLC SALTVILLE, VIRGINIA		
SALTVILLE WELL CH-18					JOB No. 50407C
: TM	DRAWN: RCR	CHECKED: TM	DATE: 8/03	SCALE: NONE	DRAWING No. 50407C-LC-016



pths measured from BHF.
ence 1973 well plugging records and Virginia
ipeline well conversion workover records.

Energy Storage Services, Inc. Engineering Construction Operations 11757 KATY FREEWAY #600 HOUSTON, TEXAS 77079	SALTVILLE GAS STORAGE COMPANY, LLC SALTVILLE, VIRGINIA
SALTVILLE WELL CH-19	JOB No. 50407C
TM | DRAWN: RCR | CHECKED: TM | DATE: 8/03 | SCALE: NONE	DRAWING No. 50407C-LC-017



depths measured from BHF.
erence 1973 well plugging records and Virginia
Pipeline well conversion workover records.

Energy Storage Services, Inc. Engineering Construction Operations 11757 KATY FREEWAY #600 HOUSTON, TEXAS 77079	SALTVILLE GAS STORAGE COMPANY, LLC SALTVILLE, VIRGINIA

SALTVILLE WELL CH-21					JOB No. 50407C
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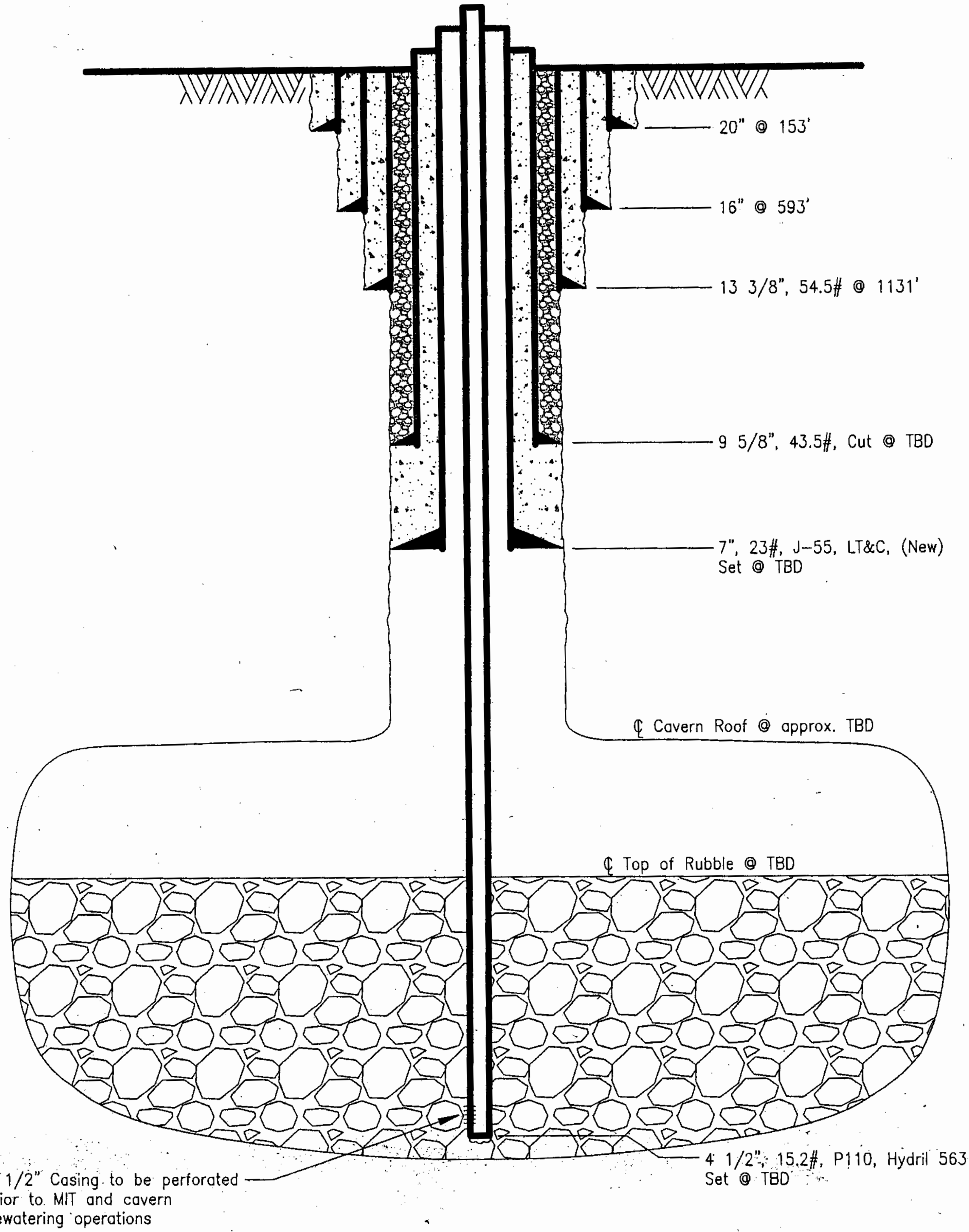

pths measured from BHF.
ence 1973 well plugging records and Virginia
ipeline well conversion workover records.

Energy Storage Services, Inc. Engineering Construction Operations 11757 KATY FREEWAY #600 HOUSTON, TEXAS 77079	SALTVILLE GAS STORAGE COMPANY, LLC SALTVILLE, VIRGINIA

SALTVILLE WELL CH-22				JOB No. 50407C
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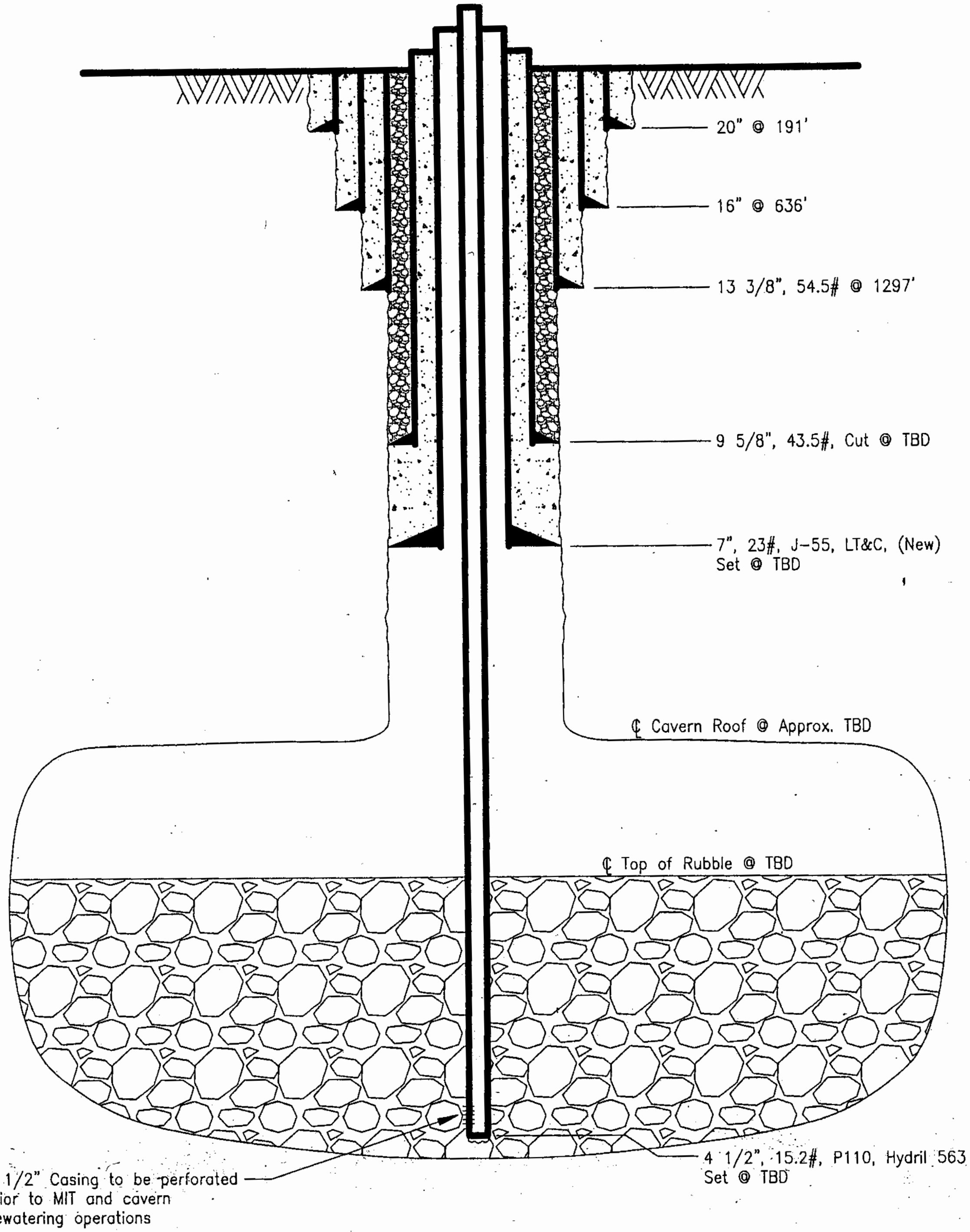
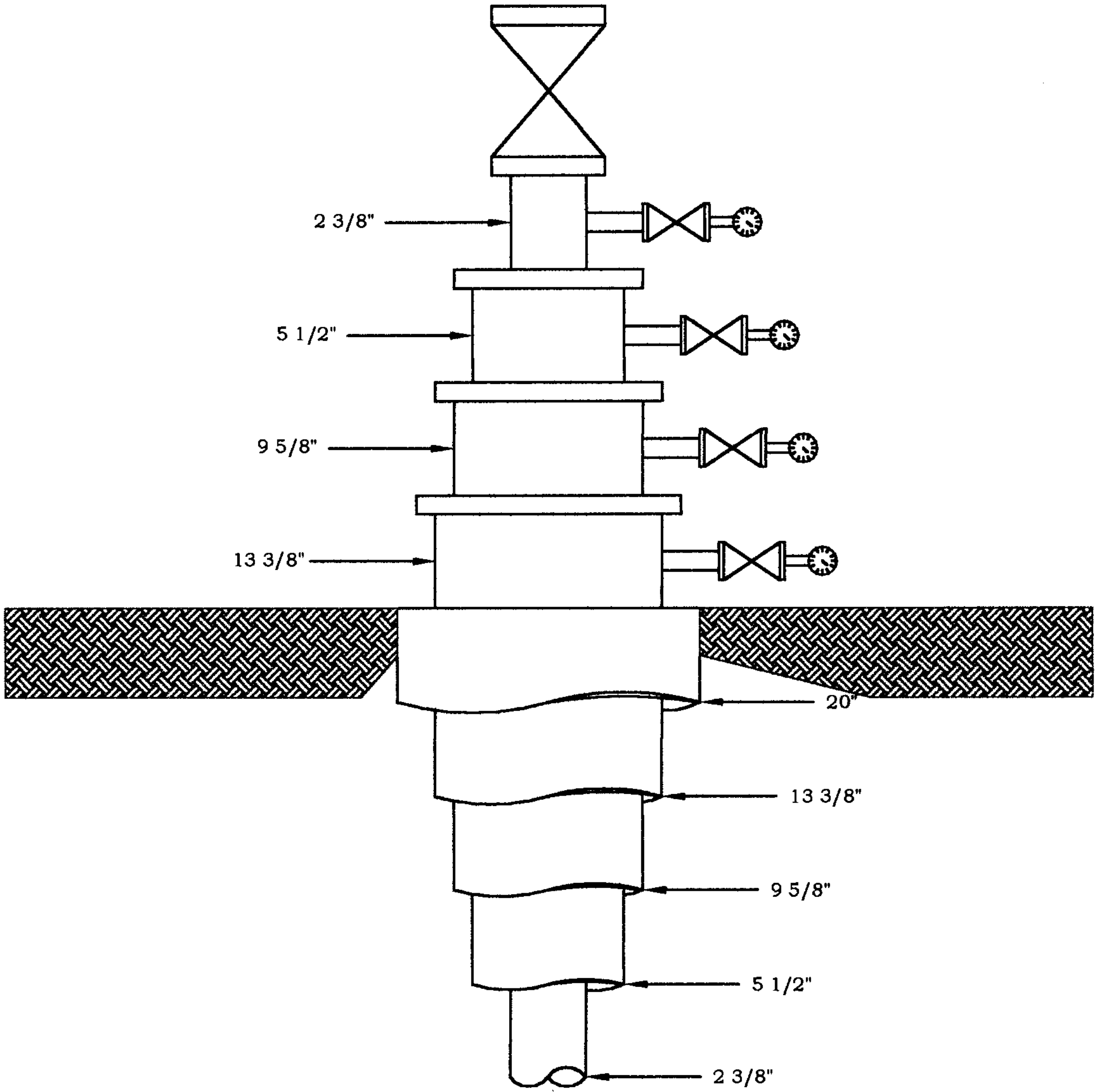


ıths measured from BHF.
nce 1973 well plugging records and Virginia
peline well conversion workover records.

:nergy Storage Services, Inc. Engineering Construction Operations 11757 KATY FREEWAY #600 HOUSTON, TEXAS 77079	SALTVILLE GAS STORAGE COMPANY, LLC SALTVILLE, VIRGINIA

SALTVILLE WELL CH-23	JOB No. 50407C

TM	DRAWN: RCR	CHECKED: TM	DATE: 8/03	SCALE: NONE	DRAWING No. 50407C-LC-020

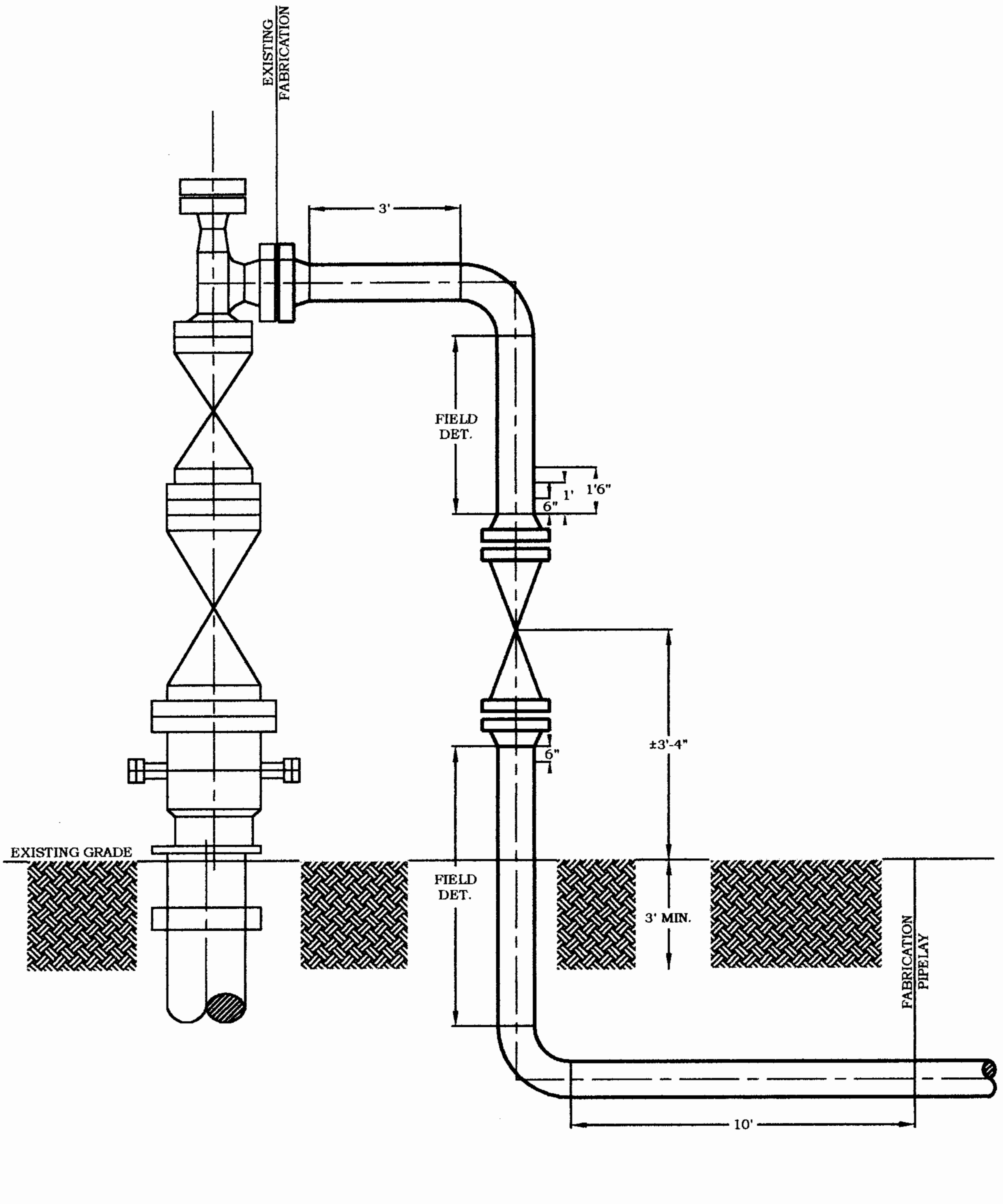


TYPICAL SURFACE DETAILS OF TEMPORARY WELLHEAD

DRAWN BY: TLR
CHECKED BY: VMM
DATE: 09-05-03
NOT TO SCALE

NUI Virginia Gas
New Ideas. Traditional Values.
200 East Main St.
Abingdon, VA 24210

LBL & ASSOCIATES, PC
ENVIRONMENTAL SERVICES DIVISION
P.O. BOX 968, CEDAR BLUFF, VA 24609
276-596-9646 (FAX: 276-596-9736)



TYPICAL SURFACE DETAILS OF PERMANENT WELLHEAD	DRAWN BY: TLR CHECKED BY: VMM	DATE: 09-05-03 NOT TO SCALE

NUI Virginia Gas
New Ideas. Traditional Values.
800 East Main St.
Abingdon, VA 24210

LBL & ASSOCIATES, PC
ENVIRONMENTAL SERVICES DIVISION
P.O. BOX 968, CEDAR BLUFF, VA 24609
276-596-9646 (FAX: 276-596-9736)

APPENDIX C
Daily Work-over Reports
And
Cement Bond Log

Saltville Storage Company
Daily Work-Over Report
Date: 5/10/01

AFE: 201

Well: CH-23 | **County:** **Washington** | **State:** **Virginia**

Activity: Phase 2: Re-entry - Drill cement out of 2 3/8" tubing with a coiled tubing unit. Day: 2

Originial Depths CSG/TBG: 13 3/8" @ 1297' | 9 5/8" @ 3041' | 5 1/2" @ 3080' | 2 3/8" @ 3086'

Work-Over Log	**Activity**
7:21 AM	Begin drilling of cement @ 55'.
8:25	drilling @ 117' (60'/hr. rate)
9:25	Drilling @ 175' (58'/hr)
10:25 AM	Drilling @ 218' (43'/hr)
11:25	Drillling @ 259' (41'/hr)
12:25 PM	Drilling @ 336' (77'/hr)
1:25	Drilling @ 427' (91'/hr)
2:25	Drilling @ 508' (81'/hr)
3:25	Drilling @ 588' (80'/hr)
4:25 PM	Drilling @ 645' (57'/hr)
	Shut Down - Trpped out of hole - examined mill

Estimated Phase 2 Cost / Total Well Cost

Daily Rig Cost: N/A

Cum. Rig Cost: N/A

Total Daily Cost: $10,700

Cum Daily Cost: $22,200

Previous Cum Daily Cost: $11,500

Total Well Cost:

Daily Rental Charges:		Daily Material Charges:		Daily Services Charges:	
				Baker Oil Tools	$3,000
				Schlumberger, Inc.	$7,200
				Supervision	$500
Total	$0	Total		Total	$10,700

AFE: 201

Saltville Storage Company
Daily Work-Over Report
Date: 5/11/01

Well: CH-23 | **County:** Washington | **State:** Virginia

Activity: Phase 2: Re-entry - Drill cement out of 2 3/8" tubing with a coiled tubing unit. Day: 3

Originial Depths CSG/TBG: 13 3/8" @ 1297' | 9 5/8" @ 3041' | 5 1/2" @ 3080' | 2 3/8" @ 3086'

Work-Over Log	Activity
7:00 AM	Tagged cement @ 657'
8:15	Drilled to 720'
9:15	Drilled to 788' (68')
10:15 AM	Drilled to 861' (73')
11:15	Drilled to 933' (72')
12:15 PM	Drilled to 985' (52')
1:15	Drilled to 1040' (55')
2:15	Drilled to 1108' (68')
3:00	Drilled to 1150' (42')
3:15	Circulated hole for 15 minutes and shut down.

Estimated Phase 2 Cost / Total Well Cost

Daily Rig Cost: N/A

Cum. Rig Cost: N/A

Total Daily Cost:	$10,000	Previous Cum
Cum Daily Cost:	$32,200	Daily Cost:
Cum Phase 2 Cost:	$32,200	$22,200

Total Well Cost:

Daily Rental Charges:		Daily Material Charges:		Daily Services Charges:	
				Baker Oil Tools	$3,000
				Schlumberger, Inc.	$6,500
				Supervision	$500
Total	$0	Total		Total	$10,000

Saltville Storage Company
Daily Work-Over Report
Date: 5/12/01

AFE: 201

Well: CH-23 | **County:** Washington | **State:** Virginia

Activity: Phase 2: Re-entry - Drill cement out of 2 3/8" tubing with a coiled tubing unit. Day: 4

Originial Depths CSG/TBG: 13 3/8" @ 1297' | 9 5/8" @ 3041' | 5 1/2" @ 3080' | 2 3/8" @ 3086'

Work-Over Log	Activity
6:55 AM	Test well head to 1000# - no leak
7:15	Start drling @ 1150'
7:40	Drill out of cement @ 1215' (Records indicated cement bottom @ 1295'.)
	Start down hole
8:50	Hit something solid at 3078'
	Continued drilling to 3084.5'.
9:30	Circulating @ 1 BPM w/ 200# pump pressure. Shut down pump (X3) and flow to mud pit would stop indicating no fluid influx from cavern.
10:30	Tripped out of hole into lubricator and an immediate fluid surge occurred. (~13 bbl into mud tank)
	The flow line was shut in and tubing pressure reached 960 psig in 42 seconds: seconds psig
	10 500#
	20 750#
	30 850#
	42 960#
11:00	Continued to test fluid flow rate. Flow rate dropped to approximately 5 gallons/15 min.
11:15	Pumped 2 bbls back into tubing to make sure tubing was open.
11:30	Rig down. Prepare to move to CH-25 on Monday.
	*The tubing will be perforated as soon as possible to allow unrestriced brine influx from cavern.
	(Cement Bond Log will be taken at the same time.)
3:00 to 4:00 PM	Removed Baker flow line connections. Re-plumbed from well head to the existing line pipe that transports brine to the tank battery.

Estimated Phase 2 Cost / Total Well Cost

Daily Rig Cost: N/A
Cum. Rig Cost: N/A

Total Daily Cost: $10,000
Cum Daily Cost: $42,200
Cum Phase 2 Cost: $42,200
Total Well Cost:

Daily Rental Charges:		Daily Material Charges:		Daily Services Charges:	
				Baker Oil Tools	$3,000
				Schlumberger, Inc.	$6,500
				Supervision	$500
Total	$0	Total		Total	$10,000

Saltville Storage Company
Daily Work-Over Report
Date: 6/5/01

CH-18 **County:** **Washington** **State:** **Virginia**

Activity: Phase 2: Re-entry - Coiled Tubing

Original Depths
CSG/TBG: 13 3/8" @ 1321' 10" #/4 @ 2925' 7" @ 2961' 2 3/8" @ 2965'

Work-Over Log	**Activity**
	MIRU
7:00 A.M.	Trip in hole Tag cement @ 248'
9:05 A.M.	Start milling out cement
12:15 P.M.	Trip out of hole @ 476' Change mill for new button mill
12:45 P.M.	Continue milling @ 476'
1:50 P.M.	Trip out of hole @ 489' Change out mill - button mill would not cut
2:20 P.M.	Continue milling @ 489'
5:25 P.M.	Stopped milling @ 750'
6:00 P.M.	Close well in. Shut down for the day. Milled out 502' of cement.

Estimated Phase 2 Cost / Total Well Cost

Daily Rig Cost: N/A
Cum. Rig Cost: N/A

Total Daily Cost: $16,098
Cum Daily Cost: $16,098
Cum Phase 2 Cost: $16,098

Previous Daily Cost $0

Total Well Cost:

Daily Rental Charges:			Daily Material Charges:		Daily Services Charges:
				Schlumberger, Inc.	$9,300
			(down hole tools)	Baker Oil Tools	$5,198
			PBKBB	Supervision	$800
			VGPC	Supervision	$800
Total		Total		Total	$16,098

Saltville Storage Company
Daily Work-Over Report
Date: 6/6/01

CH-18	**County:**	**Washington**		**State:**	**Virginia**
Activity:	Phase 2: Re-entry - Coiled Tubing				
Originial Depths CSG/TBG:	13 3/8" @ 1321'	10" #/4 @ 2925'	7" @ 2961'	2 3/8" @ 2965'	

Work-Over Log	**Activity**
7:00 A.M.	Open well had no psi. Trip in hole to 750'.
7:20 A.M.	Continue milling cement.
2:25 P.M.	Milled out of cement at 1189'.
3:30 P.M.	Tag up at 2649' Circulate well clean. Trip out of hole. Examined Mill - in gauge. Clean out run was not needed.
4:15 P.M.	Rig down move to well CH-12.
5:00 P.M.	Shut-in

Estimated Phase 2 Cost / Total Well Cost

Daily Rig Cost:	N/A	Total Daily Cost:	$14,066	Previous Cum Daily Cost	$16,098
		Cum Daily Cost:	$30,164		
Cum. Rig Cost:	N/A	Cum Phase 2 Cost:	$30,164		
				Total Well Cost:	

Daily Rental Charges:		Daily Material Charges:		Daily Services Charges:	
				Schlumberger, Inc.	$9,300
			(down hole tools)	Baker Oil Tools	$3,166
			PBKBB	Supervision	$800
			VGPC	Supervision	$800
Total		Total		Total	$14,066

Saltville Storage Company
Daily Work-Over Report
Date: 6/12/01

CH-18	**County:**	**Washington**	**State:**	**Virginia**	
Activity:	Phase 2: Re-entry - Perforating				
Originial Depths CSG/TBG:	13 3/8" @ 1321'	10" #/4 @ 2925'	7" @ 2961'	2 3/8" @ 2965'	

Work-Over Log	**Activity**
6/12/2001	
6:50 PM	Rig up wire line unit.
7:45 PM	Trip in hole to 2600' perforate tubing with 3 shots at 2 shots P/F.
8:00 PM	Trip out of hole. Well had 300 Psi.
8:15 PM	Rig down and release wire line unit.
6/13/2001	Shut-in
	6/12/2001
Well#	Time-Pressure
CH-25	5PM Flow Test
CH-26	Flow Test
CH-27	680#
CH-28	580#
CH-23	240#
CH-22	270#
CH-21	300#
CH-18	300#

Estimated Phase 2 Cost / Total Well Cost

Daily Rig Cost:	N/A	Total Daily Cost:	$2,825	Previous Cum Daily Cost	$30,164
		Cum Daily Cost:	$32,989		
		Cum Phase 2 Cost:	$32,989		
Cum. Rig Cost:	N/A			Total Well Cost:	

Daily Rental Charges:		Daily Material Charges:		Daily Services Charges:	
				Allegheny Wire Line	$2,825
Total		Total		Total	$2,825

Saltville Storage Company
Daily Work-Over Report
Date: 5/18/01

AFE: 201

Well: CH-22 **County:** **Washington** **State:** **Virginia**

Activity: Phase 2: Re-entry - Drill cement out of 2 3/8" tubing with a coiled tubing unit. Day: 1

Originial Depths CSG/TBG: 13 3/8" @ 1131' 9 5/8" @ 3055' 5 1/2" @ 3099' 2 3/8" @ 3133'

Work-Over Log	Activity
11:00 AM	MIRU
12:00 noon	Trip in hole, tag cement @ 78'. Begin drilling.
1:00 PM	Drilling cement @ 193' (115')
1:10 PM	Down hole motor locking up. Tripped out of hole / change motors / tripped back in hole
2:30 PM	Drilling cement @ 320' (127')
3:30 PM	Drilling cement @ 460' (140')
4:30 PM	Drilling cement @ 598'
4:35 PM	Drilling cement @ 605' Shut-in

Estimated Phase 2 Cost / Total Well Cost

Daily Rig Cost: N/A
Cum. Rig Cost: N/A

Total Daily Cost: $16,000
Cum Daily Cost: $16,000

Previous Daily Cost $0

Total Well Cost:

Daily Rental Charges:		Daily Material Charges:		Daily Services Charges:	
				Baker Oil Tools	$6,000
				Schlumberger, Inc.	$9,500
				Supervision	$500
Total		Total		Total	$16,000

Saltville Storage Company
Daily Work-Over Report
Date: 5/19/01

AFE: 201

Well: CH-22 **County:** Washington **State:** Virginia

Activity: Phase 2: Re-entry - Drill cement out of 2 3/8" tubing with a coiled tubing unit. Day: 2

Originial Depths CSG/TBG: 13 3/8" @ 1131' 9 5/8" @ 3055' 5 1/2" @ 3099' 2 3/8" @ 3133'

Work-Over Log	Activity
6:45 AM	Start in hole
6:55 AM	Tagged cement @ 606'. Start drilling on cement.
7:55 AM	Drilling cement @ 713' (107')
8:55 AM	Drilling cement @ 809' (96')
9:55 AM	Drilling cement @ 918' (109')
10:55 AM	Drilling cement @ 1015' (97')
11:55 AM	Drilling cement @ 1120' (105')
12:55 PM	Drilling cement @ 1217" (97')
1:20 PM	Drilled out of cement @ 1291'.
2:15 PM	Tagged TD @ 3091'. Tripped out of hole. ISIP 680# (same as CH-23/CH-21)
2:50 PM	Picked up a fully gauged mill. Tripped back in hole. Tagged TD @ 3091'.
3:45 PM	Tripped out and shut-in.

Estimated Phase 2 Cost / Total Well Cost

Daily Rig Cost: N/A
Cum. Rig Cost: N/A

Total Daily Cost: $18,000
Cum Daily Cost: $34,000
Cum Phase 2 Cost: $34,000

Previous Daily Cost $16,000

Total Well Cost:

Daily Rental Charges:		Daily Material Charges:		Daily Services Charges:	
				Baker Oil Tools	$4,500
				Schlumberger, Inc.	$13,000
				Supervision	$500
Total		Total		Total	$18,000

Saltville Storage Company
Daily Work-Over Report
2/1/2002

AFE: 201

Well: CH-22 | **County:** Washington | **State:** Virginia

Activity: Phase 2: Re-entry - Run GR/CBL/Perf for Phase 2

Originial Depths CSG/TBG: 13 3/8" @ 1131' | 9 5/8" @ 3055' | 5 1/2" @ 3099' | 2 3/8" @ 3133'

Work-Over Log	**Activity**
	Ran GR/CBL Log for Phase 2
	Perf. 2 3/8" tubing - (11) .25" Holes 2795' to 2805'
	(Well can potentially be used to dispose of brine, etc.

Estimated Phase 2 Cost / Total Well Cost

Daily Rig Cost: N/A

Cum. Rig Cost: N/A

Total Daily Cost: $7,500
Cum Daily Cost: $41,500

Previous Daily Cost $34,000

Total Well Cost:

Daily Rental Charges:		Daily Material Charges:		Daily Services Charges:	
				Baker Atlas	$7,000
				Supervision	$500
Total		Total		Total	$7,500

Cement Bond Log for Wells CH-18, CH-19, and CH-21

Performed on 7" Casing shoe using a 0.80 pressure gradient

Well No.	Test Date	Pressure	Duration	Casing Shoe Depth
CH-18	4/22/2003	1,200 lbs.	30 minutes	2,470'
CH-19	6/11/2003	1,200 lbs.	30 minutes	2,520'
CH-21	8/6/2003	1,200 lbs.	30 minutes	2,540'

CH-22	To be tested once 7" casing is set
CH-23	To be tested once 7" casing is set

Test performed by:

Witnessed by: